

CHAPTER 5: Fuel Standard Feasibility

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In this chapter, we present the methodology used to develop the costs which would result from the proposed fuel program, as well as the projected costs themselves. In Section 5.1, we estimate the volumes of diesel fuel which would be affected by the 500 and 15 ppm sulfur caps in various phases of the proposed fuel program. In Section 5.2, we evaluate a wide variety of distillate desulfurization technologies which refiners could potentially use to meet 500 and 15 ppm sulfur caps. In Section 5.3, we formally assess the technical feasibility of the 500 ppm sulfur cap in 2007, including the sufficiency of the leadtime provided refiners. In Section 5.4, we assess the feasibility of distributing the 500 ppm sulfur fuel which would be required in 2007. In Section 5.5, we formally assess the technical feasibility of the 15 ppm sulfur cap in 2010, including the sufficiency of the leadtime provided refiners. In Section 5.6, we assess the feasibility of distributing the 15 ppm sulfur fuels which would be required in 2010. Finally, in Section 7.6, we project the possible impacts of the proposal on diesel fuel prices.

5.1 Blendstock Properties of Non-Highway Diesel Fuel

5.1.1 Blendstocks Comprising Non-highway Diesel Fuel and their Sulfur Levels

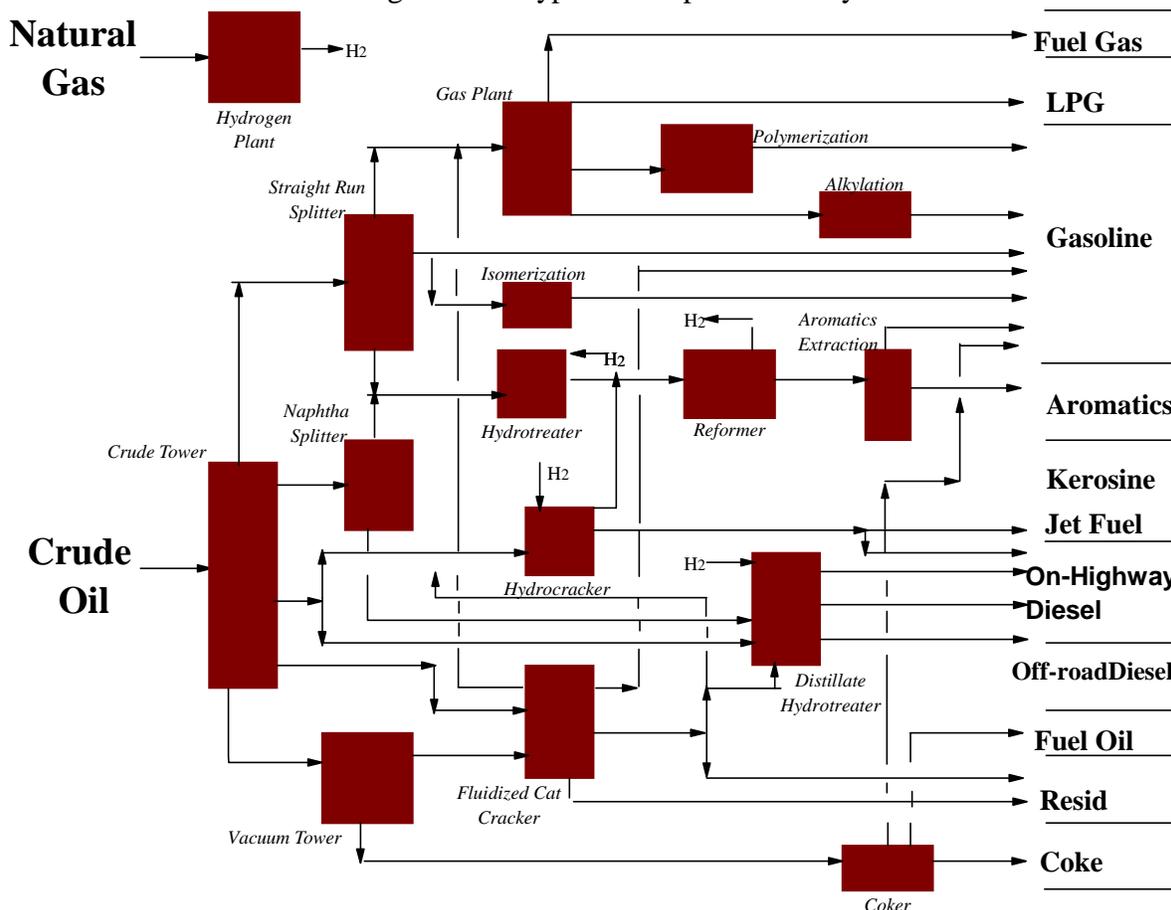
The primary sources of sulfur in diesel fuel are the sulfur-containing compounds which occur naturally in crude oil.^A Depending on the source, crude oil contains anywhere from fractions of a percent of sulfur, such as less than 0.05 weight percent (500 ppm) to as much as several weight percent.¹ The average amount of sulfur in crude oil refined in the U.S. is about one weight percent.² Most of the sulfur in crude oil is in the heaviest boiling fractions. Since most of the refinery blend stocks that are used to manufacture diesel fuel come from the heavier boiling components of crude oil, they contain substantial amounts of sulfur.

The distillate^B produced by a given refinery is composed of one or more blend stocks from crude oil fractionation and conversion units at the refinery. Refinery configuration and equipment, and the types and relative volumes of products manufactured (the product slate) can significantly affect the sulfur content of diesel fuel. The diagram on the following page illustrates the configuration and equipment used at a typical complex refinery in the U.S.

^A Additives that contain sulfur are sometimes intentionally added to diesel fuel. For a discussion how the addition of these additives will be affected under this program, see Section IV.D.5.

^B Distillate refers to a broad category of fuels falling into a specific boiling range. Distillate fuels have a heavier molecular weight and therefore boil at higher temperatures than gasoline. Distillate includes diesel fuel, kerosene and home heating oil. For the purposes of this discussion, we will focus on number 2 distillate which comprises the majority of diesel fuel and heating oil.

Figure 5.1-1
Diagram of a Typical Complex Refinery



Refineries differ from the model in the preceding diagram depending on the characteristics of the crude oils refined, and their product slate. For example:

- Refineries that process lighter crude oils are less likely to have coker and hydrocracker units.
- Refinery streams that can be used to manufacture diesel fuel can also be used in the manufacture of heating oil, kerosene and jet fuel. Much of the distillate product from the hydrocracker is often blended into jet fuel rather than diesel fuel and current highway regulations generally require that a refinery have a hydrotreater which usually would not be necessary if the refinery produced only heating oil.

On an aggregate basis, most of the distillate manufactured in the U.S. comes from the crude fractionation tower (called straight run or SR). Most of the remainder comes from the fluid catalytic cracker (FCC) conversion unit (called light cycle oil or LCO). The remaining small fraction of diesel fuel volume comes from a coker conversion unit or other units which crack

heavy compounds such as a visbreaker or steam cracker (called other cracked stocks in this document), or from the hydrocracker conversion unit (called hydrocrackate).

To comply with the current federal regulatory requirement on the sulfur content of highway diesel fuel (500 ppm cap), the blendstock streams from these process units are typically further processed to reduce their sulfur content. Desulfurization of highway diesel blendstocks is currently accomplished in fixed-bed hydrotreaters that operate at moderate pressures (500-800+ psi)³. Nearly all of the low-sulfur diesel blendstocks come from such hydrotreaters. However, a small amount of low-sulfur diesel also comes from hydrocrackers operating at pressures of 500 - 3000 psi, although most operate at 1500 - 3000 psi, which naturally produces distillate fuel with sulfur levels of about 100 ppm.

To comply with applicable sulfur standards, which range from 2000-5000 ppm, or the 40 cetane standard for non-highway diesel fuel, some of the distillate blendstocks used to produce non-highway diesel fuel and heating oil are hydrotreated. A significant amount of hydrocracked distillate is also blended into non-highway diesel fuel and heating oil. As will be discussed in Chapter 7, the use of hydrotreated blendstocks in non-highway diesel fuel has important implications for the cost of desulfurizing NRLM diesel fuel.

The distillate blendstocks used to produce non-highway diesel fuel and their sulfur content vary considerably from refinery to refinery. A survey conducted by the American Petroleum Institute (API) and National Petroleum Refiners Association (NPRA) in 1996 examined the typical blendstock properties for the U.S. highway and the non-highway diesel pools.⁴ The results of this survey for the non-highway distillate pool are contained in Table 5.1-1.

Table 5.1-1
Average Composition and Sulfur Content of the Non-highway Distillate Pool Outside of California in 1996⁵

Type of Distillate Stream	Diesel Blendstock	Percentage	Sulfur Content (ppm)
Unhydrotreated	Straight Run	45	2274
	Light Cycle Oil (LCO)	12	3493
	Coker Gas Oil	1	2345
	Unhydrotreated Subtotal	58	-
Hydrotreated	Hydrotreated Straight Run	18	353
	Hydrotreated LCO	10	1139
	Hydrotreated Coker Gas Oil	4	270
	Hydrocrackate	10	115
	Hydrotreated Subtotal	42	-
	Total	100	-

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As shown in Table 5.1-1, approximately 42 percent of all blendstocks used to manufacture non-highway distillate outside of California are hydrotreated to reduce their sulfur content. This includes hydrocrackate (10 percent of the non-highway distillate pool), which is desulfurized to a substantial extent as a necessary element of the hydrocracking process and is not further processed in a hydrotreater. Table 5.1-1 also shows that approximately 58 percent of non-highway distillate comes from nonhydrotreated blendstocks. As expected, the sulfur levels of the hydrotreated blendstocks are lower than the nonhydrotreated distillate blendstocks.

5.1.2 Current Levels of Other Fuel Parameters in Non-highway Distillate

It is useful to review other qualities of high sulfur distillate, as well as sulfur content, for a couple of reasons. First, some of the desulfurization technologies affect these other fuel properties. Second, as will be discussed further below, some sulfur compounds are more difficult to treat than others. Refiners could potentially try to shift these more difficult compounds to fuels which face less stringent sulfur standards. Their ability to do this depends in part on the effect of such shifts on non-sulfur properties and whether or not these other properties still meet industry specifications. Thus, it is helpful to evaluate the degree to which current non-highway distillate fuels meet or exceed their applicable industry standards.

Data on the current distillation characteristics, API gravity, pour point, natural cetane level, and aromatics content of diesel fuel blendstocks are contained in the Table 5.1-2.

Table 5.1-2
Average Non-highway Distillate Fuel Property Levels by Geographic Area^{6 7}
(Data from 1997 API/NPRA Survey unless specified)

Fuel Parameter	PADD 1	PADD 2	PADD 3	PADD 4	PADD 5 (CA Excluded)	U.S. (CA Excluded)	CA	
API Gravity	32.6	34.1	32.6	35.6	33.8	32.8	30.8	
Cetane Number ^a	N/A	N/A	N/A	N/A	N/A	47	N/A	
Pour Point (°F) [additized]	-6	-8	0	6	12	-1	4	
Pour Point Depressant Additive (ppmw)	0	71	0	13	0	18	0	
Distillation (°F)	T10	434	425	418	411	466	419	498
	T30	492	476	457	443	517	464	
	T50	517	508	502	499	542	503	556
	T70	545	558	536	522	570	539	
	T90	613	604	598	591	616	595	620

^a From 1997 NIPER/TRW survey data, U.S. average includes California. N/A means not available.

The American Society for Testing Materials (ASTM) has established consensus standards which apply to #2 non-highway diesel fuel, as well as for #2 distillate fuel (e.g., heating oil).⁸ The specifications which are most relevant to desulfurization are summarized in Table 5.1-3.

Table 5.1-3
ASTM Specifications which Apply to Non-Highway Distillate Fuels

	#2 Diesel Fuel (Non-highway)	#2 Fuel Oil/Heating Oil	#2 Marine Distillate (DMA)
T-90 Min °F	540	540	—
T-90 Max °F	640	640	—
Density max (g/cm ³) (API Gravity min)	None	0.876 (30.0)	0.890 (27.5)
Pour Point max °F		21.2	21.2
Cloud Point °F	46 to -0.4		
Sulfur max (ppm)	5000	5000	
Cetane Number min	40		40

Comparing Tables 5.1-2 and 5.1-3 shows that the average properties of current non-highway distillate are within the specifications, and for some properties, well within specifications. For example, except for California, the T90 of current non-highway diesel fuel is 25-40°F below the maximum allowed. The average cetane number of all non-highway distillate is well above the minimum of 40. Finally the pour point is well below the maximum allowed for fuel oil/heating oil and marine distillate fuel. One exception is that the API gravity of non-highway distillate fuel in PADDs 1 and 3, which includes the heating oil used in the Northeast, is just above the minimum.

While refiners might try to perform such shifts in blendstocks between fuels, it should be noted that we did not assume that refineries would be shifting blendstocks between various distillate fuels in order to reduce the compliance costs associated with the proposed NRLM diesel fuel sulfur standards. Instead, we projected the use of desulfurization techniques which would be sufficient to meet the proposed sulfur standards without shifting more difficult to treat sulfur compounds to other fuels. This approach appeared reasonable given that we were evaluating the potential of over 100 refineries which currently produce non-highway distillate fuel to reduce NRLM diesel fuel sulfur. The ability to shift blendstocks between fuels to reduce costs would be very refinery specific and difficult to estimate on average across a wide range of refineries. Also, two primary types of shifts are possible and both have limits. One approach would be to shift the heaviest portion of selected blendstocks such as LCO to the bunker or residual fuel pool, avoiding the need to desulfurize this material. However, the market for these heavy fuels is limited and on a national basis, this approach is generally not economically feasible. The other approach would be to shift these difficult to treat streams and portions of streams to heating oil, which must meet less stringent sulfur standards. This would likely require the addition of additional product tankage and require more refineries to produce lower sulfur NRLM diesel

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fuel. The material being shifted to heating oil could still require additional desulfurization to ensure that ASTM and state standards were still being met. Thus, there would be a cost trade-off, not just a cost reduction. Again, given the national scale of this analysis, we decided to avoid the projection of such shifts and limit our analysis to the desulfurization of current non-highway diesel fuel blendstocks.

5.2 Evaluation of Diesel Fuel Desulfurization Technology

5.2.1 Introduction to Diesel Fuel Sulfur Control

As mentioned in Section 5.1, the sulfur in diesel fuel comes from the crude oil processed by the refinery. One way to reduce the amount of sulfur in diesel fuel, therefore, is to process a crude oil that is lower in sulfur. Some refiners already do this. Others could switch to low or at least lower sulfur crude oils. However, there is limited capability worldwide to produce low sulfur crude oil. While new oil fields producing light, sweet crude oil are still being discovered, most of the new crude oil production being brought on-line is heavier, more sour (i.e., higher sulfur) crude oils. The incentive to use low sulfur crude oils has existed for some time and low sulfur crude oils have traditionally commanded a premium price relative to higher sulfur crude oils. While a few refiners with access to lower sulfur crude oil could potentially reduce their diesel sulfur levels in this way, it is not feasible for most, let alone all U.S. refiners to switch to low sulfur crude oils to meet a tighter diesel fuel sulfur standard. In addition, while helpful, a simple change to a low sulfur crude oil may fall short of compliance with the 500 ppm sulfur cap standard, and certainly fall short of the 15 ppm sulfur cap standard. Thus, changing to a sweeter crude oil was not considered to be viable for complying with the proposed nonroad, locomotive and marine diesel sulfur standards.

Another method to reduce diesel fuel sulfur, but much more significantly, is to chemically remove sulfur from the hydrocarbon compounds which comprise diesel fuel. This is usually accomplished through catalyzed reaction with hydrogen at moderate to high temperature and pressure. A couple of specific examples of this process are hydrotreating and hydrocracking. A modified version of hydrotreating which operates solely in the liquid state was announced recently. Another process was announced recently which uses a moving bed catalyst to both remove and adsorb the sulfur using hydrogen at moderate temperature and pressure. There are other low temperature and pressure processes being developed which don't rely on hydrotreating, such as biodesulfurization, and chemical oxidation. Sulfur can be removed via these processes up front in the refinery, such as from crude oil, before being processed in the refinery into diesel fuel. Or, sulfur can be removed from those refinery streams which are to be blended directly into diesel fuel. Finally, another method to moderately reduce diesel fuel sulfur is to shift sulfur-containing hydrocarbon compounds to other fuels produced by the refinery.

After careful review of all these approaches, we expect that the sulfur reduction which would be required by the proposed 2007 500 ppm sulfur cap standard would occur through chemical removal via conventional hydrotreating. For complying with the proposed 15 ppm cap standard for nonroad diesel fuel which would be required in 2010, we expect that it would be met

primarily through adsorption and liquid phase hydrotreating, which are emerging advanced desulfurization technologies. Thus, this section will begin with a relatively detailed discussion of the capabilities of these various processes. Refiners may use the other methods to obtain cost effective sulfur reductions which will complement the primary sulfur reduction achieved via hydrotreating and adsorption. These other methods, such as FCC feed hydrotreating, biodesulfurization, and chemical oxidation will be discussed following the primary discussion of distillate hydrotreating, liquid phase hydrotreating and adsorption. Another means for aiding the desulfurization of diesel fuel, particularly to comply with the 15 ppm cap standard, is undercutting which removes the most difficult to treat sulfur compounds. Since undercutting can help ease the task of complying with the 15 ppm cap standard for any of the desulfurization technologies, we provide a discussion of undercutting below in this subsection.

5.2.2 Conventional Hydrotreating

Hydrotreating generally combines hydrogen with a hydrocarbon stream at high temperature and pressure in the presence of a catalyst. Refineries currently employ a wide range of these processes for a number of purposes. For example, naphtha (gasoline like material which itself does not meet gasoline specifications, such as octane level) being fed to the refinery reformer is always hydrotreated to remove nearly all sulfur, nitrogen and metal contaminants which would deactivate the noble metal catalyst used in the reforming process. Similarly, feed to the FCC unit is often hydrotreated to remove most of the sulfur, nitrogen and metal contaminants in order to improve the yield and quality of high value products, such as gasoline and distillate, from the FCC unit. Refineries currently producing highway diesel fuel which must meet a 500 ppm cap standard hydrotreat their distillate to remove much of the sulfur present and to improve the cetane. That same unit or another hydrotreating unit in the refinery also hydrotreats some of the refinery streams used to blend up nonhighway distillate. EPA expects that nearly all refiners will hydrotreat the naphtha produced by the FCC unit to remove most of the sulfur present to comply with the Tier 2 gasoline sulfur standards.⁹

If the temperature or pressure is increased sufficiently and if a noble metal catalyst is used, hydrotreating can more dramatically affect the chemical nature of the hydrocarbons, as well as remove contaminants. For example, through a process called hydrocracking, smaller, lighter molecules are created by splitting larger, heavier molecules. In the process, nearly all of the contaminants are removed and olefins and aromatics are saturated into paraffins and naphthenes. Outside the U.S., this process is commonly used to produce distillate from heavier, less marketable refinery streams. In the U.S. the hydrocracker is most often used to produce gasoline from poor quality distillate, such as LCO from the FCC unit.

A few refineries also currently hydrotreat their distillate more severely than is typical, but not as severely as hydrocracking. Their intent is to remove the sulfur, nitrogen and metallic contaminants and to also saturate most of the aromatics present. This is done primarily in Europe to meet very stringent specifications for both sulfur and aromatics applicable to certain diesel fuels and encouraged by reduced excise taxes. This severe hydrotreating process is also used in the U.S. to “upgrade” petroleum streams which are otherwise too heavy or too low in

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quality to be blended into the diesel pool, by cracking some of the material to lower molecular weight compounds and saturating some of the aromatics to meet the distillation and cetane requirements. A different catalyst which encourages aromatic saturation is used in lieu of one that simply encourages contaminant removal.

To meet the 500 ppm and the 15 ppm diesel fuel sulfur cap standards, EPA expects refiners to focus as much as possible on sulfur removal. Other contaminants, such as nitrogen and metals, are already sufficiently removed by existing refinery processes. While saturation of aromatics generally improves cetane, the cetane numbers of today's nonroad, locomotive and marine diesel fuels are already sufficient to comply with the ASTM standards which apply. Thus, refiners would want to avoid saturating aromatics to avoid the additional cost of increased hydrogen consumption. Consequently, we anticipate refiners will choose desulfurization processes that minimize the amount of aromatics saturation. Current diesel fuel already meets all applicable specifications, and hydrotreating to remove sulfur should not degrade quality, except possibly lubricity, as discussed in Section C. Thus, with this one exception, there should be no need to improve diesel fuel quality as a direct result of this new diesel sulfur standard. Should a refiner choose to do so, it would be to improve profitability,^C and not related to meeting the 15 ppm sulfur cap standard.

5.2.2.1 Fundamentals of Distillate Hydrotreating

Essentially all distillate hydrotreater designs follow the same broad format. Liquid distillate fuel is heated to temperatures of 300-380°C, pumped to pressures of 500-700 psia, mixed with hydrogen, and passed over a catalyst. Hydrogen reacts with sulfur and nitrogen atoms contained in the hydrocarbon molecules, forming hydrogen sulfide and ammonia. The resulting vapor is then separated from the desulfurized distillate. The desulfurized distillate is usually simply mixed with other distillate streams in the refinery to produce diesel fuel and heating oil.

The vapor still contains a lot of valuable hydrogen, because the reaction requires the use of a significant amount of excess hydrogen to operate efficiently and practically. However, the vapor also contains a significant amount of hydrogen sulfide and ammonia, which inhibit the desulfurization and denitrogenation reactions and must be removed from the system. Thus, the hydrogen leaving the reactor is usually mixed with fresh hydrogen and recycled to the front of the reactor for reaction with fresh distillate feed. If not, this would cause a build up of hydrogen sulfide and ammonia in the system, since it would have no way to leave the system. In some cases, the hydrogen sulfide and ammonia are chemically scrubbed from the hydrogen recycle stream. In other cases, a portion of the recycle stream is simply purged from the system as a mixture of hydrogen, hydrogen sulfide and ammonia. The latter is less efficient since it leads to

^C Refiners can choose to “upgrade” heavy refinery streams which do not meet the cetane and distillation requirements for highway diesel fuel. The process for doing so is also called ring opening, since one or more of the aromatic rings of heavy, aromatic molecules are opened up, improving the value of the stream. Upgrading the heavy refinery streams to highway diesel fuel improves the stream’s market price by 10 - 30 c/gal.

higher levels of hydrogen sulfide and ammonia in the reactor, but it avoids the cost of building and operating a scrubber.

Desulfurization processes in use today in the U.S. generally use only one reactor, due to the need to only desulfurize diesel fuel to 500 ppm or slightly lower. However, a second reactor can be used, particularly to meet lower sulfur levels. Instead of liquid distillate fuel going to the diesel fuel/heating oil pool after the first reactor, it would be stripped of hydrogen sulfide and ammonia and mixed with fresh hydrogen and sent to the second reactor.

Traditional reactors are cocurrent in nature. The hydrogen is mixed together with the distillate at the entrance to the reactor and flow through the reactor together. Because the reaction is exothermic, heat must be removed periodically. This is sometimes done through the introduction of fresh hydrogen and distillate fuel in the middle of the reactor. The advantage of cocurrent design is practical, it eases the control of gas-liquid mixing and contact with the catalyst. The disadvantage is that the concentration of hydrogen is the highest at the front of the reactor where the easiest to remove sulfur is and lowest at the outlet where the hardest to remove sulfur is. The opposite is true for the concentration of hydrogen sulfide. This increases the difficulty of achieving extremely low sulfur levels due to the low hydrogen concentration and high hydrogen sulfide concentration at the end of the reactor.

The normal solution to this problem is to design a counter-current reactor, where the fresh hydrogen is introduced at one end of the reactor and the liquid distillate at the other end. Here, the hydrogen concentration is highest (and the hydrogen sulfide concentration is lowest) where the reactor is trying to desulfurize the most difficult (sterically hindered) compounds. The difficulty of counter-current designs in the case of distillate hydrotreating is vapor-liquid contact and the prevention of hot spots within the reactor. The SynAlliance (Criterion Catalyst Corp., and Shell Oil Co.) has patented a counter-current reactor design called SynTechnology. With this technology, in a single reactor design, the initial portion of the reactor will follow a cocurrent design, while the last portion of the reactor will be counter-current. In a two reactor design, the first reactor could be cocurrent, while the second reactor could be counter-current.

ABB Lummus estimates that the counter-current design can reduce the catalyst volume needed to achieve 97 percent desulfurization by 16 percent relative to a cocurrent design.¹⁰ The impact of the counter-current design is even more significant when aromatics control (or cetane improvement) is desired in addition to sulfur control.

Sulfur containing compounds in distillate can be classified according to the ease with which they are desulfurized. Sulfur contained in paraffins or aromatics with a single aromatic ring are relatively easy to desulfurize. These molecules are sufficiently flexible so that the sulfur atom is in a geometric position where it can make physical contact with the surface of the catalyst. The more difficult compounds are contained in aromatics consisting of two aromatic rings, particularly dibenzothiophenes. Dibenzothiophene contains two benzene rings which are connected by a carbon-carbon bond and two carbon-sulfur bonds (both benzene rings are bonded to the same sulfur atom). This compound is essentially flat in nature and the carbon atoms bound

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to the sulfur atom hinder the approach of the sulfur atom to the catalyst surface. Despite this, today's catalysts are very effective in desulfurizing dibenzothiophenes, as long as only hydrogen is attached to the carbon atoms bound directly to the sulfur atom.

However, distillate fuel can contain dibenzothiophenes which have methyl or ethyl groups bound to the carbon atoms which are in turn bound to the sulfur atom. These extra methyl or ethyl groups further hinder the approach of the sulfur atom to the catalyst surface. Dibenzothiophenes with such methyl or ethyl groups are commonly referred to as being sterically hindered. An example of a dibenzothiophene with a single methyl or ethyl group next to the sulfur atom is 4-methyl dibenzothiophene. An example of a dibenzothiophene with two methyl or ethyl groups next to the sulfur atom is 4,6-dimethyl dibenzothiophene. In 4,6-dimethyl dibenzothiophene, and similar compounds, the presence of a methyl group on either side of the sulfur atom makes it very difficult for the sulfur atom to react with the catalyst surface to assist the hydrogenation of the sulfur atom.

Most straight run distillates contain relatively low levels of these sterically hindered compounds. LCO contains the greatest concentration of sterically hindered compounds, while other cracked distillate streams from the coker and the visbreaker contain levels of sterically hindered compounds in concentrations between straight run and LCO. Thus, LCO is generally more difficult to desulfurize than coker distillate which is in turn more difficult to treat than straight run distillate.¹¹ In addition, cracked stocks, particularly LCO, have a greater tendency to form coke on the catalyst, which deactivates the catalyst and requires its regeneration or replacement.

The greater presence of sterically hindered compounds in LCO is related to two fundamental factors. First, LCO contains much higher concentrations of aromatics than typical SRLGO.¹² All sterically hindered compounds are aromatics. Second, the chemical equilibria existing in cracking reactions favors the production of sterically hindered dibenzothiophenes over unsubstituted dibenzothiophenes. For example, in LCO, methyl substituted aromatics are twice as prevalent as unsubstituted aromatics. Di-methyl aromatics are twice as prevalent as methyl aromatics, or four times more prevalent as unsubstituted aromatics. Generally, desulfurizing 4-methyl dibenzothiophene using conventional desulfurization is 6 times slower than desulfurizing similar non-sterically hindered molecules, while desulfurizing 4,6-dimethyl dibenzothiophene using conventional desulfurization is 30 times slower. Slower reactions mean that either the volume of the reactor must be that much larger, or that the reaction must be somehow speeded up. The latter implies either a more active catalyst, higher temperature, or higher pressure. These alternatives will be discussed later below.

Because moderate sulfur reduction is often all that is required in current distillate hydrotreating, catalysts have been developed which focus almost exclusively on sulfur and other contaminant removal, such as nitrogen and metals. The most commonly used desulfurization catalyst consists of a mixture of cobalt and molybdenum (Co/Mo). These catalysts interact primarily with the sulfur atom and encourage the reaction of sulfur with hydrogen.

Other catalysts have been developed which encourage the saturation (hydrogenation) of the aromatic rings. As mentioned above, this generally improves the quality of the diesel fuel produced from this distillate. These catalysts also indirectly encourage the removal of sulfur from sterically hindered compounds by eliminating one or both of the aromatic rings contained in dibenzothiophene. Without one or both of the rings, the molecule is much more flexible and the sulfur atom can approach the catalyst surface much more easily. Thus, the desulfurization rate of sterically hindered compounds is greatly increased through the hydrogenation route. The most commonly used hydrogenation/desulfurization catalyst consists of a mixture of nickel and molybdenum (Ni/Mo).

There are a number important issues which should be highlighted about using the hydrogenation pathway for desulfurization. As pointed out above, one or both of the aromatic rings are being saturated which significantly increases the consumption of hydrogen. It is important that one of the aromatic rings of a polyaromatic compound is saturated, as this is the facilitating step which results in the desulfurization of a sterically hindered compound. If the mono aromatic compounds are also saturated, there would only be a modest improvement in the desulfurization reaction rate of the sterically hindered compounds, however, at a large hydrogen cost. In addition, certain diesel fuel qualities, such as cetane, would improve significantly as more of the aromatic compounds are saturated. However, the vendors of diesel desulfurization technology explained to us that if cetane improvement is not a goal, then the most cost effective path to desulfurize the sterically hindered compounds is to saturate the polyaromatic compounds to monoaromatic compounds, but not to saturate the monoaromatic compounds. The vendors tell us that because the concentration of the monoaromatic compounds is at equilibrium conditions within the reactor, the monoaromatic compounds are being both saturated and unsaturated, which helps to enable the desulfurization of these compounds. It also means that the concentration can be controlled temperature and pressure.

The vendors also point out a number of reasons why the cycle length of the catalysts which catalyze hydrogenation reactions, which would likely occur in a second stage, is longer than the first stage desulfurization catalyst. First, the temperature at which the hydrogenation reactions occur to saturate the polyaromatic compounds to monoaromatic compounds, but not to saturate the monoaromatic compounds is significantly lower than the temperature of the first stage. The lower temperature avoids color change problems and reduces the amount of coke formation on the hydrogenation catalyst. Furthermore, since the first stage has somewhat “cleaned” the diesel fuel of contaminants such as sulfur, nitrogen and metals, the catalyst in this second hydrogenation stage is not degraded as quickly. Because the second stage would have a cycle length which is as long as or longer as the first stage, adding the second stage is not expected to shorten the cycle length of the current distillate hydrotreater.

If refiners are “upgrading” their diesel fuel by converting heavy, high aromatic, low cetane, stocks to 15 ppm diesel fuel sulfur standard, they are intentionally reacting a lot of hydrogen with the diesel fuel. The hydrogen reactions with the diesel fuel saturates many or most of the aromatics, increases cetane number and greatly eases the reduction of sulfur. The lower concentration of aromatics and improved cetane of the upgraded feedstock would then allow the

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product to be sold as highway diesel fuel. The much higher sales price of the highway diesel fuel compared to the lower value of the feedstock justifies the much larger consumption in hydrogen and the cost of a larger reactor.

Up to a certain level of sulfur removal, the CoMo catalyst is generally preferred. It is more active with respect to desulfurizing non-sterically hindered compounds, which comprise the bulk of the sulfur in distillate, straight run or cracked. Below that level, the need to desulfurize sterically hindered compounds leads to greater interest in NiMo catalysts. Acreon Catalysts had indicated that NiMo are preferred for deep desulfurization around 15 ppm due to this catalyst's ability to saturate aromatic rings and make the sulfur atom more accessible to the catalyst. On the other hand, Haldor-Topsoe has performed studies which indicate that CoMo catalysts may still have an advantage over NiMo catalysts, even at sulfur levels below 50 ppm.¹³

Two-stage processes may also be preferable to achieve ultra-low sulfur levels. Both stages could emphasize desulfurization or desulfurization could be emphasized in the first stage and hydrogenation/desulfurization emphasized in the second stage. In addition to this advantage, the main advantage of two stages lies in the removal of hydrogen sulfide from the gas phase after the first stage. Hydrogen sulfide strongly inhibits desulfurization reactions, as will be discussed further in the next section. It can also recombine with non-sulfur containing hydrocarbon compounds at the end of the reactor or even in subsequent piping, essentially adding sulfur to the desulfurized distillate. Removing hydrogen sulfide after the first stage reduces the hydrogen sulfide concentration at the end of the second stage by roughly two orders of magnitude, dramatically reducing both inhibition and recombination.

In one study, Haldor-Topsoe analyzed a specific desulfurized 50/50 blend of SRGO and LCO at 150 ppm sulfur and found that essentially all of the sulfur is contained in sterically hindered compounds.¹⁴ This feed contains more LCO than would be processed in the typical refinery. A refinery processing less LCO would presumably reach the point where the sulfur compounds were dominated by sterically hindered compounds at a lower sulfur level. They also compared the performance of CoMo and NiMo catalysts on a SRLGO feed at the same space velocity. The NiMo catalyst performed more poorly than the CoMo catalyst above 200 ppm sulfur, and better below that level. This implies that much of the sulfur left at 200 ppm (and even above this level) was sterically hindered. These two studies indicate that the amount of sterically hindered compounds can exceed the 15 ppm sulfur cap by a substantial margin.

In addition to NiMo catalysts, precious metal catalysts are also very effective in desulfurizing sterically hindered compounds. An example of a precious metal catalyst is the ASAT catalyst developed by United Catalysts and Sud-Chemie AG, which uses both platinum and palladium.¹⁵ They are most commonly used to more severely dearomatize distillate and increase cetane by opening up the aromatic rings, a process called ring opening.

5.2.2.2 Meeting a 15 ppm Cap with Distillate Hydrotreating

Using distillate hydrotreating to meet a 15 ppm sulfur cap on diesel fuel has been commercially demonstrated, as will be discussed below. Thus, meeting the 15 ppm cap is quite feasible using current refining technology. Assessing the most reliable and economic means of doing so is more complicated. Refiners already hydrotreat their highway diesel fuel to meet a 500 ppm sulfur cap. These hydrotreaters use a variety of catalysts and have a range of excess capacity. Thus, refiners are not all starting from the same place. Many refiners would also be producing locomotive and marine diesel fuel which would have to meet a 500 ppm cap and heating oil which only needs to meet a 5000 ppm cap, which would have less stringent sulfur requirements and could, for example, provide a place to blend the sterically hindered sulfur-containing compounds. Finally, the amount of cracked stocks that a refiner processes into diesel fuel varies widely. Those with a greater fraction of LCO would face a more difficult task of complying with a 15 ppm cap, than those processing primarily straight run distillate.

To understand the types of modifications which can be made to current distillate hydrotreating to improve its performance, it is useful to better understand the quantitative relationships between the various physical and chemical parameters involved in hydrotreating. Haldor-Topsoe has developed the following algebraic expression to describe the rate of desulfurization via both direct desulfurization and hydrogenation/desulfurization.

$$\begin{array}{l} \text{Rate of} \\ \text{Desulfurization} \\ \text{Per Catalyst} \\ \text{Surface Area} \end{array} = \frac{k \times C_s^n \times P_{H_2}^a}{(1 + K_{H_2S} \times P_{H_2S})} + \frac{k \times C_s^m \times P_{H_2}^b}{(1 + K_F \times C_F)}$$

Where:

k , K_{H_2S} and K_F are various rate constants, which only vary with temperature.

C_s is the concentration of sulfur in the distillate.

P_{H_2} and P_{H_2S} are the partial pressures of hydrogen and hydrogen sulfide in the vapor phase.

$K_F \times C_F$ is the total inhibition due to hydrogen sulfide, ammonia, and aromatics n , m , a , and b are various constant exponents.

The first term represents the rate of direct desulfurization, such as that catalyzed by CoMo. This reaction rate increased by increasing the partial pressure of hydrogen. However, it is inhibited by increasing concentrations of hydrogen sulfide, which competes with the distillate for sites on the catalyst surface.

The second term represents the rate of desulfurization via hydrogenation of the aromatic ring next to the sulfur atom. This rate of desulfurization also increases with higher hydrogen partial pressure. However, this reaction is inhibited by hydrogen sulfide, ammonia, and aromatics. This inhibition by aromatics leads to the presence of a thermodynamic equilibrium condition which can prevent the complete saturation of aromatics. Also, this inhibition makes it more difficult to desulfurize cracked stocks, which contain high concentrations of both sterically hindered sulfur compounds and aromatics. While the literature generally expresses a preference for NiMo catalysts for desulfurizing cracked stocks, Haldor-Topsoe has found situations where this

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aromatics inhibition leads them to favor CoMo catalysts even for desulfurizing feeds with a high concentration of sterically hindered compounds.

These relationships essentially identify the types of changes which could be made to improve the performance of current distillate hydrotreaters. First, a more active catalyst can be used. This increases the “k” terms in the above equations. Second, temperature can be increased, which also increases the “k” terms in the above equations. Third, improvements can often be made in vapor-liquid contact, which effectively increases the surface area of the catalyst. Fourth, hydrogen purity can be increased. This increases the hydrogen concentration, which the P_{H_2} term in the two numerator terms of the equation. Fifth, the concentration of hydrogen sulfide in the recycle stream can be removed by scrubbing. This decreases the P_{H_2S} and C_F terms in the two denominator terms of the equation. Finally, more volume of catalyst can be used, which increases the surface area proportionally.

Regarding catalysts, at least two firms have announced the development of improved catalysts since the time that most distillate hydrotreaters were built in the U.S. to meet the 1993 500 ppm sulfur cap: Akzo Nobel / Nippon Ketjen Catalysts (Akzo Nobel) and Haldor-Topsoe. Akzo Nobel currently markets four CoMo desulfurization catalysts: KF 752, KF 756 and KF 757 which have been available for several years, and KF 848, which was announced in year 2000.¹⁶ KF 752 can be considered to be typical of an Akzo Nobel catalyst of the 1992-93 timeframe, while KF 756 and 757 catalysts represent improvements. Akzo Nobel estimates that under typical conditions (e.g., 500 ppm sulfur), KF 756 is 25 percent more active than KF 752, while KF 757 is more than 50 percent more active than KF 752 and 30 percent more active than KF 756.¹⁷ However, under more severe conditions (e.g., <50 ppm sulfur), KF 757 is 35-75 percent more active than KF 756. KF 848 is 15 - 50 percent more active than KF 757. Commercial experience exists for both advanced catalysts. KF 756 is widely used in Europe (20 percent of all distillate hydrotreaters operating on January 1, 1998), while KF 757 has been used in at least three hydrotreaters commercially. KF 757 and KF 842 utilizes what Akzo Nobel calls STARS technology, Super Type II Active Reaction Sites. Type II refers to a specific kind of catalyst site which is particular good at removing sulfur from sterically hindered compounds.

In terms of sulfur removal, Akzo Nobel projects that a desulfurization unit producing 500 ppm sulfur with KF 752, would produce 405, 270 and 160ppm sulfur with KF 756, KF757, and KF 842, respectively.

In 2001, Akzo Nobel announced a new highly active catalyst named Nebula which offers a different way in which coatings are used for catalysts. A typical catalyst is composed of two parts: an active coating which contains metals and a generally inactive substrate. For Nebula, Akzo Nobel concentrated the metal coatings and omitted the substrate. Because of the very high metals content, Nebula costs several times more than conventional catalysts. The higher activity of the Nebula catalyst leads to an increased tendency for coking, which must be countered by using a high hydrogen partial pressure, resulting in a higher hydrogen consumption. (The hydrogen consumption is higher because a higher percentage of the aromatics are saturated to nonaromatic compounds.) According to Akzo Nobel, a refiner may be able to meet the 15 ppm

sulfur standard by simply replacing its existing catalyst with Nebula and providing significantly more hydrogen (which may possibly require the addition of a hydrogen plant). Nebula is a new catalyst that could avoid some or much of the capital investment that would otherwise be required for meeting the 15 ppm sulfur standard.

Haldor-Topsoe has also developed a more active catalyst. Its TK-554 catalyst is analogous to Akzo Nobel's KF 756 catalyst, while its newer, more active catalyst is termed TK-574. For example, in pilot plant studies, under conditions where TK-554 produces 400 ppm sulfur in SRLGO, TK 574 will produce 280 ppm. Under more severe conditions, TK-554 will produce 60 ppm, while TK 574 will produce 30 ppm. Similar benefits are found with a mixture of straight run and cracked stocks.

UOP projects a similar reduction in sulfur due to an improved catalyst. They estimate that a hydrotreater producing 500 ppm sulfur distillate today (20% LCO, 10% light coker gas oil) could produce 280 ppm sulfur distillate with a 50 percent more active catalyst.¹⁸

Over the last four years, Criterion Catalyst Company announced two new lines of catalysts. One is called Century, and the other is called Centinel.¹⁹ These two lines of catalysts are reported to be 45 - 70 percent and 80 percent more active, respectively, at desulfurizing petroleum fuel than conventional catalysts used in the mid-90s. These improvements have come about through better dispersion of the active metal on the catalyst substrate.

Another catalyst vendor shared some information about its catalyst development program which involves advances in the geometry of its substrate. These advances have resulted in significant improvements in the contact of diesel fuel with the catalyst. The vendor also shared that it is combining its substrate technology with other reactor enhancements to further increase the contact between diesel fuel and the catalyst and hydrogen. Preliminary tests suggest that this combination could improve the catalyst activity by at least a minimum of two.

Thus, by itself, changing to a more active catalyst can reduce sulfur significantly. Based on the history of the industry, improvements in catalyst performance can be anticipated over time to result in roughly a 25 percent increase in catalyst activity every 4 years. Vendors have informed EPA that the cost of these advanced catalysts is very modest relative to less active catalysts. This will help to reduce the reactor size needed.

The second type of improvement which can be made to improve 500 ppm hydrotreating is to reduce the concentration of hydrogen sulfide, which reduces the inhibition of the desulfurization and hydrogenation reactions. Hydrogen sulfide can be removed by chemical scrubbing. Haldor-Topsoe indicates that decreasing the concentration of hydrogen sulfide at the inlet to a co-current reactor by three to six volume percent can decrease the average temperature needed to achieve a specific sulfur reduction by 15-20°C, or reduce final sulfur levels by more than two-thirds. UOP projects that scrubbing hydrogen sulfide from recycle hydrogen can reduce sulfur levels from roughly 285 to 180 ppm in an existing hydrotreater.

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The third type of improvement which can be made to current distillate hydrotreating is to improve vapor-liquid contact. Akzo Nobel estimates that an improved vapor-liquid distributor can reduce the temperature necessary to meet a 50 ppm sulfur level by 10 °C, which in turn would increase catalyst life and allow an increase in cycle length from 10 to 18 months. Based on the above data from Haldor-Topsoe, if temperature were maintained, the final sulfur level could be reduced by 50 percent. Similarly, in testing of an improved vapor-liquid distributor in commercial use, Haldor-Topsoe found that the new distributor allowed a 30 percent higher sulfur feed to be processed at 25°C lower temperatures, while reducing the sulfur content of the product from 500 to 350 ppm. Maintaining temperature should have allowed an additional reduction in sulfur of more than two-thirds. Thus, ensuring adequate vapor-liquid contact can have a major impact on final sulfur levels.

The fourth type of improvement possible is to increase hydrogen partial pressure and/or purity. As discussed above, this increases the rate of both desulfurization and hydrogenation reactions. Haldor-Topsoe indicates that increasing hydrogen purity is preferable to a simple increase in the pressure of the hydrogen feed gas, since the latter will also increase the partial pressure of hydrogen sulfide later in the process, which inhibits both beneficial reactions. Haldor-Topsoe projects that an increase in hydrogen purity of 30 percent would lower the temperature needed to achieve the same sulfur removal rate by eight to nine °C. Or temperature could be maintained while increasing the amount of sulfur removed by roughly 40 percent. Hydrogen purity can be increased through the use of a membrane separation system or a PSA unit. UOP project that purifying hydrogen can reduce distillate sulfur from 180 to 140 ppm from an existing hydrotreater.

The fifth type of improvement is to increase reactor temperature. Haldor-Topsoe has shown that an increase of 14°C while processing a mix of SRLGO and LCO with its advanced TK-574 CoMo catalyst will reduce sulfur from 120 ppm to 40 ppm.²⁰ UOP projects that a 20 °F increase in reactor temperature would decrease sulfur from 140 to 120 ppm. The downside of increased temperature is reduced catalyst life (i.e., the need to change catalyst more frequently). This increases the cost of catalyst, as well as affects highway diesel fuel production while the unit is down for the catalyst change. Still, current catalyst life currently ranges from six to 60 months, so some refiners could increase temperature and still remain well within the range of current industry performance. The relationship between temperature and life of a catalyst is a primary criterion affecting its marketability. Thus, catalyst suppliers generally do not publish these figures.

Sixth, additional sulfur can be removed by increasing the amount of recycle gas sent to the inlet of the reactor. However, the effect is relatively small. Haldor-Topsoe indicates that a 50 percent increase in the ratio of total gas/liquid ratio only decreases the necessary reactor temperature by six to eight °C. Or, temperature can be maintained and the final sulfur level reduced by 35-45 percent.

Seventh, reactor volume can be increased. UOP projects that doubling reactor volume would reduce sulfur from 120 to 30 ppm.

These individual improvements described cannot be simply combined, either additively or multiplicatively. As mentioned earlier, each existing distillate hydrotreater is unique in its combination of design, catalyst, feedstock, and operating conditions. While the improvements described above are probably indicative of improvements which can be made in many cases, it is not likely that all of the improvements mentioned are applicable to any one unit; the degree of improvement could either be greater than, or less than the benefits that are indicated.

Therefore, many refiners may have to implement one additional technical change listed by UOP to be able to meet the 15 ppm cap standard. This last technical change is to add a second stage to current single stage 500 ppm hydrotreaters. This second stage would consist of a second reactor, and a high pressure, hydrogen sulfide scrubber between the first and second reactor. The compressor would also be upgraded to allow a higher pressure to be used in the new second reactor. Assuming use of the most active catalysts available in both reactors, UOP projects that converting from a one-stage to a two-stage hydrotreater could produce 5 ppm sulfur relative to a current level of 500 ppm today.

In addition to these major technological options, refiners may have to debottleneck or add other more minor units to support the new desulfurization unit. These units could include hydrogen plants, sulfur recovery plants, amine plants and sour water scrubbing facilities. All of these units are already operating in refineries but may have to be expanded or enlarged.

Overall, Akzo-Nobel projects that current hydrotreaters can be modified short of a revamp to achieve 50 ppm sulfur. Acreon/IFP/Procatalyse is less optimistic, believing that more than a catalyst change will be necessary to meet this sulfur level.²¹ BP-Amoco projects that a 70 percent improvement in catalyst activity could reduce sulfur from a current hydrotreater meeting a 500 ppm sulfur specification to 30 ppm.²² While this improvement is somewhat greater than the 50 percent improvement measured by Akzo Nobel at current desulfurization severity, it indicates that it may be possible to improve current hydrotreaters to produce distillate sulfur levels in the 50-100 ppm range. Thus, it appears that additional reductions needed to meet a 15 ppm cap would require additional measures. To assess the degree that these measures would be needed, it is useful to examine the commercial and pilot plant performance of distillate hydrotreaters to achieve very low sulfur levels.

5.2.2.3 Low Sulfur Performance of Distillate Hydrotreating

Data from both pilot plant studies and commercial performance are available which indicate the capability of various hydrotreating technologies to reduce distillate sulfur levels to very low levels. While many reports of existing commercial operations are available which focus on reducing sulfur to meet a 500 ppm sulfur standard or somewhat below that sulfur level, studies of achieving lower sulfur levels (e.g., 10-50 ppm) are associated with also reducing aromatics content significantly. This combination is related to the fact that Swedish Class II diesel fuel must meet a tight aromatics specification in 2005 along with a 10 ppm sulfur cap standard. Other European diesel fuel must also meet a 10 ppm sulfur cap standard.

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Another study projected the technology and resulting cost to reduce sulfur for EPA, the Engine Manufacturers Association retained Mathpro for this study. The projections of this study will be discussed in the next chapter on the economic impacts of this rule. The discussion in this chapter will focus on the available pilot plant and commercial data demonstrating the achievement of low sulfur levels. It is worth noting that until the 15 ppm cap standard was established for highway diesel fuel in the U.S. and the announcements by the German government to seek sulfur levels as low as 10 ppm, there had been little effort by industry to develop technology capable of such a level across the diesel pool. Recent advancements by catalyst manufacturers demonstrating the feasibility of producing diesel fuel which meets these levels through pilot plant testing and some commercial demonstrations should be considered a first-generation of technology, with new and continual advancements expected over time.

Starting with SynTechnology, as of August 2, 1999, there were 24 units either in operation or in the process of being constructed. The purpose for each of those units ranged from desulfurization to desulfurization plus dearomatization to mild hydrocracking. Of particular interest here is a revamp of an existing two reactor distillate hydrotreater at the Lyondell-Citgo refinery in Texas. The revamped unit was designed to process a low-cost feed very heavily weighted towards cracked material (65-70 percent LCO and LCGO). One existing reactor was converted to SynSat Technology, while the other was used simply as a flash drum. A new first-stage reactor was added. Both reactors were designed to operate in a co-current fashion. Pilot plant studies predicted average sulfur and aromatics levels of seven ppm and 31 volume percent, respectively, based on feed sulfur and aromatics levels of 11,900 ppm and 53 volume percent, respectively. The unit exceeded expectations in the case of sulfur, producing an average sulfur level of less than five ppm from a feed sulfur level of 13,800 ppm. The actual aromatic level achieved was above the target by four volume percent, but the feed aromatic level was five volume percent higher than expected. Thus, the net reduction in aromatic content in terms of volume percent was still higher than found in the pilot plant. ABB Lummus and Criterion indicate that their catalyst technology is sufficiently flexible to focus on the deep desulfurization with or without the significant aromatics reduction seen here. This is reflected in their projection of the technology needed to meet a 15 ppm sulfur cap which is discussed in the next chapter.

While this two-stage unit initially produced less than 5 ppm product, it does not do so consistently. The primary purpose of the unit is to increase cetane so that the product can be blended directly into diesel fuel. The primary sulfur reduction requirement is to protect the noble metal catalyst in the second stage reactor. This generally requires that the product from the first stage be less than 50 ppm. Thus, if the cetane specification is being met at less severe sulfur reduction conditions, there is no incentive to reduce sulfur any further than necessary for catalyst protection. In addition, the unit is seeing a heavier feedstock than designed, and the desulfurization reactor is being operated at a lower temperature than designed to increase the cycle lengths.

IFP, in conjunction with various catalyst manufacturers, offers its Prime D technology for deep desulfurization, aromatics saturation and cetane improvement.²³ Using a NiMo catalyst, IFP's Prime D process can produce distillate sulfur levels of 10 ppm from SRLGO and of less

than 20 ppm from distillate containing 20-100 percent cracked material using a single stage reactor. With a two-stage process, less than one ppm sulfur can be achieved.

United Catalysts and Sud-Chemie AG have published data on the performance of their ASAT catalyst, which uses platinum and palladium.²⁴ The focus of their study was to reduce aromatics to less than 10 volume percent starting with a feed distillate containing up to 500 ppm sulfur and at least 100 ppm nitrogen. Starting with a feed distillate containing 400 ppm sulfur and 127 ppm nitrogen and 42.5 volume percent aromatics, the ASAT catalyst was able to reduce sulfur to eight to nine ppm, essentially eliminate nitrogen and reduce aromatics to two to five volume percent. Hydrogen consumption was 800-971 standard cubic feet per barrel (SCFB).

Akzo Nobel recently presented a summary of the commercial experience of about a years worth of operations of their STARS catalyst for desulfurizing diesel fuel at the BP-Amoco refinery in Grangemouth, UK.²⁵ The original unit was designed to produce 35,000 barrels per day of diesel fuel at 500 ppm treating mostly straight run material, but some LCO was treated as well. Akzo Nobel's newest and best catalyst (KF 757 at that time) was dense-loaded^D into the reactor to produce 45,000 barrels per day diesel fuel at 10 - 20 ppm (to meet the 50 ppm cap standard). From the data, it was clear to see that as the space velocity changed, the sulfur level changed inversely proportional to the change in space velocity. Usually when the space velocity dipped below 1.0, the sulfur level dropped below 10 ppm. At that refinery, however, it was not necessary to maintain the sulfur level below 10 ppm.

These studies indicate the commercial feasibility of producing diesel fuel with 10 ppm or less sulfur. The primary issue remaining is to commercially demonstrate that the 15 ppm cap standard can be met using the desulfurization/hydrogenation method without saturating much of the aromatics in diesel fuel, especially with a feedstock blend which contains a substantial amount of cracked material. The ease or difficulty of accomplishing this depends on the amount of cracked stocks that the refiner blends into diesel fuel. A few refiners have the possibility of shifting some of the sterically hindered compounds to fuels complying with less stringent sulfur standards, such as off-highway diesel fuel and heating oil. However, our desulfurization technology feasibility analysis did not considered the occurrence of feedstock shifting as necessary for refiners to meet the proposed diesel sulfur standards.

5.2.3 Phillips S-Zorb Sulfur Adsorption

A prospective diesel desulfurization process was announced by Phillips Petroleum in late 2001.²⁶ This process is an extension of their S-Zorb process for gasoline and thus is called S-Zorb for diesel fuel. The process is very different from conventional diesel fuel hydrotreating in that instead of reacting the sulfur with hydrogen over a catalyst to form H₂S, the S-Zorb process adsorbs the sulfur molecule onto a sorbent for later removal. At a pressure of 275 - 500 pounds per square inch gauge (psig) and at a temperature of 700 - 800 Fahrenheit and in the presence of

^D Dense loading is a process of packing a certain volume of catalyst into a smaller space than conventional catalyst loading.

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hydrogen in the S-Zorb reactor, the sulfur atom of the sulfur-containing compounds adsorbs onto the sorbent. The catalyst activity of the sorbent next cleaves the sulfur atom from the sulfur-containing hydrocarbon. To prevent the accumulation of sulfur on the catalyst, the catalyst is continually removed from the reactor. From the reactor, the sorbent is moved over to a receiving vessel by an inert lift gas, which likely is nitrogen, and then in the receiving vessel the lift gas and the entrained diesel fuel is removed from the sorbent. The sorbent next drops down into a lockhopper which facilitates the movement of the sorbent to the regenerator. In the regeneration vessel, the sulfur is burned off of the sorbent with oxygen and the generated SO₂ is sent to the sulfur plant. The regenerated sorbent then drops down into a reducer vessel where the sorbent is returned back to its active state. The sorbent is then recycled back to the reactor for removing more sulfur. Because the catalyst is continuously being regenerated, Phillips estimates that the unit will be able to operate 4 - 5 years between shutdowns. Because untreated distillate can contain several percent sulfur, Phillips believes that its S-Zorb process for diesel could get overwhelmed by the amount of sulfur which is adsorbing onto the catalyst. However, some refiners who run sweet crudes and produced low sulfur non-highway diesel volumes (from straight run diesel and hydrocrackate diesel) may have lower uncontrolled nonroad sulfur levels. These refiners may be able to use the S-Zorb process to lower their nonroad diesel sulfur. Thus, the S-Zorb process may not be able to economically treat all untreated distillate streams which are high in sulfur, and would be best suited to treat distillate containing 500 ppm sulfur or less.

Phillips has been involved in sorbent technology at least as far back as 1980 which is when the company filed a patent application for sorbent technology. However, it seems apparent that Phillips did not develop its S-Zorb technology until much later as it filed for a patent for a technology for circulating sorbent during March of 1997. The purpose of the March, 1997 patent was to remove hydrogen sulfide. The technical focus of that patent was both the sorbent chemistry and the sorbent handling technology. The catalyst content was specified to be alumina, silica, zinc oxide and metal oxide (probably in the form of nickel oxide) and the sorbent size was specified to be in the range of 20 to 500 micrometers. Then in August of 1999, Phillips filed a patent for using its sorbent recirculating technology to desulfurize cracked gasoline and diesel fuels. The sorbent change as specified in the patent was to add substantially reduced valence nickel to enable the removal of sulfur from the targeted refinery streams. Then Phillips filed a patent in May of 2001 for an improved catalyst to desulfurize cracked gasoline and diesel fuel. The change was to add a calcium compound which increases the porosity of the sorbent and increases the resistance to deactivation. The latest patent also listed the potential candidates for metal promoters to include cobalt, nickel, iron, manganese, copper, molybdenum, silver, tungsten tin and vanadium, or mixtures of these metal oxides, with valences of 2 or less.

Phillips' S-Zorb diesel desulfurization process has been demonstrated in a pilot plant which started up in early 2002. This pilot plant has provided Phillips data on how the unit would operate processing varying formulations of diesel fuel or diesel fuel blendstocks. The pilot plant testing data which has been released by Phillips has shown that diesel fuels blended with LCO can be desulfurized down below 5 ppm. Phillips has also shown that straight run diesel fuel can be desulfurized below measurable levels and a 100 percent LCO stream can be desulfurized down to 10 ppm. These testing results are summarized in chapter 7 where we use the data to

develop the inputs for our refinery cost model. Phillips is constructing a commercial unit to demonstrate their S-Zorb diesel desulfurization unit. Phillips is completing the engineering phase of this project to design this unit and is expected to begin the construction for an estimated start-up date during early 2004.

While the S-Zorb diesel desulfurization process has not been demonstrated commercially, Phillips has demonstrated the S-Zorb technology for desulfurizing gasoline. An S-Zorb gasoline desulfurization unit started up at Phillips' Borger refinery in April of 2001. According to Phillips, their gasoline desulfurization unit has operated as designed for the past two years. The successful demonstration of their gasoline desulfurization unit at Borger has interested many refiners in using S-Zorb gasoline desulfurization process for complying with the upcoming Tier 2 gasoline sulfur program. Starting in 2004 many refiners will need to be starting up their gasoline desulfurization units for complying with the 30 ppm Tier 2 gasoline sulfur standard which phases in from 2004 to 2006. Phillips shared with us in late 2002 that they have licensed their S-Zorb for gasoline processing for installation in 9 refineries. That the Borger S-Zorb gasoline desulfurization unit has operated as designed and that there are 9 new S-Zorb gasoline units planned to start up demonstrates that there is agreement within the refining industry that the S-Zorb process works.

Much of the refining industry's trust with the S-Zorb gasoline desulfurization unit is likely to apply to S-Zorb for diesel fuel as well. First, the sorbent has been shown to be effective at adsorbing sulfur, releasing the sulfur when it is burned and then at being regenerated for reuse. Also, the S-Zorb unit has been shown to be able to move the sorbent out of the reactor into a number of different vessels for handling and treatment and then recycling back to the reactor. The part of diesel fuel desulfurization which cannot be demonstrated with the S-Zorb gasoline desulfurization unit is how effectively the sorbent would be able to adsorb and cleave the sulfur molecule from the sulfur-containing molecules of diesel fuel. However, that part of the S-Zorb diesel fuel desulfurization unit should be able to be demonstrated with testing in the pilot plant. Phillips can even test the diesel fuels from specific refineries in their pilot plant to help design the S-Zorb unit for those refineries. Thus, Phillips is marketing its diesel fuel desulfurization unit even before their diesel fuel desulfurization commercial demonstration unit has started up.

Most refiners, however, are very conservative and would not be willing to only rely on pilot plant testing for a unit which would likely cost tens of millions of dollars, and without its proper operation they might not be able to operate. Thus, they would want to see a particular technology operating as a commercial unit for a significant period of time, such as two years, before trusting that the technology is reliable.

Since the process has never been demonstrated commercially on diesel fuel, the commercial demonstration unit will go a long way toward proving to refiners that the Phillips process works as designed. In particular, the sulfur compounds in diesel fuel are different, usually more refractory, than those in gasoline. Phillips reports, though, that the absorption catalyst more readily desulfurizes the sterically hindered sulfur compounds than the thiophenes (single ring compounds which contain sulfur) which must be desulfurized in gasoline. This suggests the

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possibility that S-Zorb for diesel may actually desulfurize diesel fuel more easily than gasoline. Phillips projects that they will have an S-Zorb diesel desulfurization commercial unit up and running during the first quarter of 2004. After hearing Phillips' timeline for developing the S-Zorb diesel desulfurization process, and understanding the scrutiny by refiners for new desulfurization processes, it seems that refiners may consider this process too risky for complying with the 500 ppm cap in 2007, especially since the demonstration unit will be a revamp of an existing hydrotreating unit for producing 15 ppm diesel fuel. However, after seeing the commercial unit producing 15 ppm sulfur for the Highway Program for several years, we believe that this process will be a serious contender for 2010 for nonroad.

5.2.4 Linde Isotherming

A professor at the University of Arkansas has applied some ingenuity in reaction chemistry to diesel desulfurization. After conceiving of this process, he started a company named Process Dynamics and then took the new technology to Linde for development and eventual licensing. The reaction technology reacts diesel fuel with hydrogen, which is totally dissolved in the diesel fuel, in a plug flow reactor. Since the hydrogen gas is dissolved into the diesel fuel, the reactor only needs to be designed to handle a liquid, instead of the two phase reactors designed for conventional hydrotreating. Since only about 75 standard cubic feet of hydrogen can be dissolved into each barrel of diesel fuel and the hydrogen consumption for a particular desulfurization step can be much higher than that, this technology cannot be a once-through process. Process Dynamics solved that limitation by recycling the feed after a very short residence time in the reactor to recharge the liquid with more hydrogen and to mix this recycle with some untreated diesel fuel before sending it to the reactor. Thus, the recycled partially desulfurized diesel fuel acts like a diluent to the fresh feed controlling the hydrogen consumption, and the diesel fuel is recharged with hydrogen and sent to the reactor to be desulfurized several times as it is being treated.

The Linde Isotherming process has a couple apparent advantages over conventional desulfurization. First, since the hydrogen is already in the liquid phase, the hydrotreating reaction can occur much more quickly because, as described by Linde, the kinetics of conventional hydrotreating are mass transfer limited which is the rate at which gaseous hydrogen can transfer into the liquid phase. Linde makes this point by the following reaction equations. For conventional hydrotreating the following two equations apply:

$$rg = kg (PH_2 - P \times H_2) \text{ (rate of hydrogen mass transfer into the liquid phase)}$$

Where:

rg = transfer rate of hydrogen gas into diesel fuel.

kg = hydrogen gas mass transfer rate.

PH_2 = Partial pressure of hydrogen in the gas phase.

$P \times H_2$ = Partial pressure of hydrogen at the catalyst.

and

$r_s = k_s T[S][P \times H_2]$ (rate of desulfurization at the catalyst site)

Where:

r_s = rate of reaction of sulfur.

k_s = reaction rate constant for sulfur removal.

$P \times H_2$ = partial pressure of hydrogen at the catalyst.

T = temperature in degrees absolute.

$[S]$ = concentration of sulfur.

If the desulfurization rate of reaction (r_s) is much slower than the rate at which hydrogen can dissolve into diesel fuel (r_g), then there would probably not be any benefit for the Linde Isotherming process. However, according to Linde, the rate of reaction for desulfurization is faster than the rate of mass transfer, thus, the rate of reaction for diesel hydrotreating is limited by the mass transfer of hydrogen into diesel fuel. Thus, the Linde process increases the rate of reaction by dissolving the hydrogen needed for the reaction into the liquid phase prior to sending this liquid to the reactor. The faster rate of reaction is indicated by the fact that the Linde desulfurization process which can desulfurize a unhydrotreated distillate comprised of a typical mix of distillate blendstocks down to about 500 ppm at a space velocity of 8 hour⁻¹. Conversely, conventional hydrotreating requires a space velocity of about 2 hour⁻¹ to accomplish the same task.

There are a two important benefits to the Linde process because it has a higher space velocity. One benefit is that the amount of catalyst needed for the Linde process is lower. By definition, if the same volume of feed can be treated faster than another process, the amount of catalyst needed is proportionally lower by the inverse proportion of the space velocity. The second advantage of having a faster space velocity is that the reactors are sized much smaller to hold the lower volume of catalyst. Both of these benefits result in lower costs for the Linde Isotherming desulfurization process. The lower catalyst volume required by Linde Isotherming costs proportionally less because the Linde desulfurization process uses the same catalysts as conventional hydrotreating. Similarly, the smaller reactor volume reduces the capital costs, although in this case the cost reduction is not necessarily proportionally less as smaller reactors have a poorer economy of scale compared to larger reactors.

The Linde engineers point out that the Isotherming process also has other benefits over conventional hydrotreating. When some of the aromatics in diesel fuel are saturated during the desulfurization process, heat is generated. In the case of conventional hydrotreating, much of this heat is intentionally quenched away in an attempt to avoid excessive temperature excursions. Excessive temperature excursions and local low hydrogen concentration can lead to coking which is a constant problem with conventional hydrotreating. However, the higher space velocity of the Linde process coupled with the fact that the feed is diluted by the recycle stream allows for better control of the process temperature. Furthermore, the ready availability of hydrogen in the liquid phase along with the better temperature control prevents most of the coking from occurring. Thus the internally generated heat can be conserved, instead of being quenched away, and used to heat the process. The conserved heat means that no external heating

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is required which provides a savings in natural gas consumption relative to conventional hydrotreating. However, a small heater is still needed to heat the feed during start-up.

Another advantage of the Linde desulfurization process is that it does not need a hydrogen gas recycle compressor. Because the hydrogen pumped into solution and going to the reactor is either used up or it remains in solution, there is no residual hydrogen gas to recycle. Compressors operating at the pressures that diesel fuel desulfurization occurs are expensive, long time delivery items. Thus, by omitting the recycle gas compressor and using smaller reactors, the Linde desulfurization process saves substantial capital costs compared to conventional hydrotreating which likely means a somewhat shorter construction time. The smaller reactors and heater coupled with the fact that a recycle gas compressor is not needed means that the Linde process requires a smaller footprint compared to conventional hydrotreating

While aspects of the Linde Isotherming desulfurization process for diesel fuel desulfurization are novel compared to conventional diesel desulfurization, many aspects of the process are the same. Much of the list of required equipment is the same for the Linde process as for conventional hydrotreating. Table 5.2-1 shows both the similarities and differences between the two.

Table 5.2-1
Major Equipment Needed for Linde Isotherming and Conventional Hydrotreating

	Linde Isotherming	Conventional Hydrotreating
Heat Exchangers	Yes	Yes
Heater	Yes (small and for startup only)	Yes
Hydrogen gas compressor	Yes	Yes (for hydrogen makeup)
Mixers for dissolving hydrogen into the diesel fuel	Yes	No
Reactor (s)	Yes (2 - 4 small plug flow)	Yes (1 - 2 large trickle bed)
Reactor distributor	No	Yes
High pressure flash drum and hydrogen separator	Yes	Yes
Low pressure separator	Yes	Yes
Recycle hydrogen compressor	No	Yes
Recycle hydrogen gas scrubber	No	Yes

Linde has accumulated some data on the Isotherming desulfurization process from testing which they have done with their pilot plant. Linde started up a pilot plant in late 2001. Recently, Linde installed a commercial demonstration unit of their technology at a Giant refinery as a revamp to an existing highway hydrotreater to demonstrate compliance with the highway diesel

fuel 15 ppm sulfur cap standard which begins in mid 2006. The unit was started up in September of 2002 and the Linde engineers have been working with the refinery engineers to optimize the unit for the refinery.

5.2.5 Chemical Oxidation and Extraction

Another desulfurization technology based on chemical oxidation is being pursued by Unipure and Petrostar.²⁷ For these companies, the chemical oxidation desulfurization of diesel fuel is accomplished by first forming a water emulsion with the diesel fuel. In the emulsion, the sulfur atom is oxidized to a sulfone using catalyzed peroxyacetic acid. With an oxygen atom attached to the sulfur atom, the sulfur-containing hydrocarbon molecules becomes polar and hydrophilic and then move into the aqueous phase. These sulfone compounds can either be desulfurized or be converted to a surfactant which could be sold to the soap industry at an economically desirable price. The earnings made from the sales of the surfactant could offset much of the cost of oxidative desulfurization.

Petrostar has a bench scale pilot plant up and running and they intend to demonstrate their technology next with a commercial demonstration unit. Unipure is in the process of setting up a pilot plant and it is expected to be up and running by mid 2003.

Early in 2003, Lyondell announced that they had recently developed a chemical oxidation desulfurization technology. This process is similar in some ways to Unipure's and Petrostar's oxidation processes, but also different in some pronounced ways. The process is similar in that the process uses oxidation compounds to oxidize the sulfur compounds to sulfones and then removes relies on extraction to remove the sulfones. The differences are that instead of the using expensive peroxyacetic acid to create sulfones, this process uses t-butyl hydroperoxide oxidant to convert sulfur species in diesel to sulfones (this eliminates the need to recycle a co-oxidant acid). The oxidant is degraded t-butyl alcohol during the conversion of sulfur species to sulfones. The T-butyl alcohol by product can be converted to MTBE or isooctane or used as fuel in the refinery. T-butyl hydroperoxide is not as corrosive as peroxyacetic acid, thus Lyondell's process is projected to be constructed from less expensive metallurgy. Lyondell has demonstrated pilot plant success desulfurizing 500 ppm diesel fuel to below 10 ppm and plans to have a commercial plant operable by late 2003 to early 2004. Lyondell's technology was announced too late to be incorporated into this analysis but we intend to stay abreast as they develop this new technology .

5.2.6 FCC Feed Hydrotreating

At the beginning of this section, it was mentioned that sulfur could be removed from distillate material early or late in the refining process. Early in the process, the most practical place to remove sulfur is prior to the FCC unit. The FCC unit primarily produces gasoline, but it also produces a significant quantity of LCO.

Many refineries already have an FCC feed hydrotreating unit. The LCO from these refineries should contain a much lower concentration of sterically hindered compounds than refineries not

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hydrotreating their FCC feed. Adding an FCC feed hydrotreating is much more costly than distillate hydrotreating. Just on the basis of sulfur removal, FCC feed hydrotreating is more costly than distillate hydrotreating, even considering the need to reduce gasoline sulfur concentrations, as well. This is partly due to the fact that FCC feed hydrotreating by itself is generally not capable of reducing the level of diesel fuel sulfur to those being considered in this rule. However, FCC feed hydrotreating provides other environmental and economic benefits. FCC feed hydrotreating decreases the sulfur content of gasoline significantly, as well as reducing sulfur oxide emissions from the FCC unit. It also increases the yield of relatively high value gasoline and LPG from the FCC unit and reduces the formation of coke on the FCC catalyst. For individual refiners, these additional benefits may offset enough of the cost of FCC hydrotreating to make it more economical than distillate hydrotreating. However, these benefits are difficult to estimate in a nationwide study such as this. Also, feed hydrotreating is not expected to, by itself, enable a refinery to meet either the 500 or the 15 ppm cap standards. Thus, this study will rely on distillate hydrotreating as the primary means with which refiners would meet the 15 ppm sulfur cap. For those refiners who would choose FCC feed hydrotreating, their costs would be presumably lower than distillate hydrotreating and the costs estimated in the next chapter can then be considered to be somewhat conservative in this respect.

5.3 Feasibility of Producing 500 ppm Sulfur Nonroad Diesel Fuel in 2007

5.3.1 Expected use of Desulfurization Technologies for 2007

To enable our determination of whether it is feasible for the refining industry to meet the proposed 2007 sulfur cap standard, and also to estimate the cost of complying with the proposed sulfur standard (see Chapter 7), we needed to project the mix of technologies that would be available and used for compliance. We considered several different factors for projecting the mix of technologies which would be used. First and foremost, we considered the time which refiners will have to choose a new technology which is important because of the relatively short timeline allowed for compliance. Second, we considered whether the technology would be available for 2007 and if the technology is available, how proven it is. Third, we considered whether the technology is cost-competitive by comparing it to other technologies. If a refiner finds that technology is lower cost than another, it is more likely to use that technology. We also considered whether the technology is available from an industry-trusted vendor which has proven itself to the industry by providing other successful refining technologies and particularly if the vendor has proven itself in the U.S. Finally, we considered the capability of the vendor to meet the demand of the industry. We considered all these issues for each technology, but as described below, some of these issues are more prominent than others.

To comply with the proposed 500 ppm sulfur standard in 2007, refiners will have to decide what technology they will want to use several years before the standard needs to be met. Several years are needed to perform a preliminary design, complete a detailed design, purchase the hardware needed, obtain the air quality permits needed, and then install and start up the hardware. Since this rulemaking is expected to be promulgated sometime in 2004, this would provide refiners three full years to comply with the 500 ppm sulfur standard if it is promulgated

as predicted. Because refiners need about 3 years to complete the mentioned steps to have a working new unit, there is little time to shop around for a new desulfurization technology which is just beginning to prove itself. A thorough review of a newer technology can take months, thus if refiners do not have this extra time, they will tend toward the technologies with which they are familiar. See the next section for a more detailed discussion about the leadtime issues for the 2007 standard.

Of the various technologies which we list above for desulfurizing diesel fuel, conventional hydrotreating is by far the most familiar to refiners. Refiners are using conventional hydrotreating to meet the current highway diesel fuel 500 ppm sulfur cap standard. In the U.S. there are about 90 distillate hydrotreaters with virtually all of them being conventional hydrotreaters operating since 1993 or before. The one exception is a Linde Isotherming commercial demonstration unit which started up recently at a Giant refinery in New Mexico. Phillips S-Zorb, the two oxidation and extraction and biodesulfurization technologies are all being demonstrated by pilot plants only. Of those being demonstrated by a pilot plant, Phillips is expected to start a highway diesel fuel commercial demonstration unit in early 2004. However refiners usually want to see that a refinery unit has operated successfully for at least two years to ensure that it will operate with high reliability and low maintenance requirements.^E In 2004, biodesulfurization, oxidation and extraction are not expected to have units operating at all. Phillips may have a diesel fuel desulfurization unit operating by then, but certainly it will not be operating for two years. While Phillips has a gasoline desulfurization operating now, refiners may be skeptical that it truly demonstrates the technology for diesel desulfurization. The Linde desulfurization unit which is installed now and has started to accrue valuable commercial experience will have accumulated somewhat less than two years of commercial experience by then.

After considering the above issues, it seems that the lack of an excess of leadtime is the central issue of whether refiners will choose between conventional hydrotreating and other advanced desulfurization technologies for 2007. Refiners would not have the luxury of many months needed to carefully consider the advanced technologies which are still in the development and demonstration stage, so we believe that this issue is the most critical affecting refiners choice of desulfurization technologies for 2007. For these reasons, we believe that refiners would default to what they know will work, which is conventional desulfurization. Since there are multiple vendors which can provide the preliminary engineering design and any followup support for conventional hydrotreating, these vendors would not be overly taxed and would be able to serve the refiners which will need to put in desulfurization units for 2007.

5.3.2 Leadtime Evaluation

Refiners must have sufficient leadtime to design, construct and start up desulfurization technology to meet the 500 ppm standard if this standard is to be implemented smoothly and

^E Refiners want low maintenance refining units because they have cut back their engineering staff to reduce their refining costs to improve their margins and thus will seek units which are consistent with that strategy.

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without undue economic impacts. If one or more refiners were unable to comply on time, it would have major repercussions for the refiner and potentially for the national fuel supply. If some refiners who were planning on producing 500 ppm NRLM fuel could not do so on time and could not buy credits, they would have to sell their high sulfur distillate as heating oil, export this distillate or temporarily cease production. As discussed below in Section 5.8, heating oil would no longer be widely distributed in many markets. Thus, selling large quantities of heating oil may require distressed pricing and the absorption of trucking costs. Exportation would be very costly for refiners not located on an ocean coastline. Temporary closure obviously would result in serious financial loss. In addition, users of NRLM diesel fuel would likely face high fuel prices. Fuel prices respond quickly to supply shortages. Significant price increases would be expected if refiners were not able to fulfill demand for NRLM diesel fuel starting in June 1, 2007. Thus, providing adequate leadtime for refiners to design, construct and prove out the necessary new hydrotreaters is critical to avoiding serious economic harm to both the refining and NRLM industries.

We project that refiners would use conventional hydrotreating to meet the 500 ppm standard beginning on June 1, 2007. Of the 42 refineries projected to produce 500 ppm NRLM diesel fuel beginning in 2007, 13 are projected to do so with either no or minor modifications to their highway diesel fuel hydrotreaters. These refineries produce a relatively small volume of non-highway diesel fuel compared to their highway production. The remaining 29 refineries would need to design and construct a new hydrotreater to produce 500 ppm NRLM fuel.^F This is roughly 20% of all U.S. refineries producing transportation fuels today. Thus, the time available between the date of the final rule and June 1, 2007 must be sufficient across a wide spectrum of refiners and situations.

EPA has conducted two leadtime assessments for the refining industry in the past 4 years. One was conducted for the Tier 2 gasoline sulfur program.^G The other was conducted as part of our review of progress being made towards compliance with the 15 ppm sulfur, highway diesel fuel program.^H The results of both of these assessments are reviewed below and then applied to the proposed NRLM sulfur control program.

5.3.2.1 Tier 2 Gasoline Sulfur Program

Chapter IV of the Final RIA for the Tier 2 gasoline sulfur program presented the following table which contains the results of its leadtime assessment

^F Without the proposed small refiner provisions, an additional 20 refineries would have to produce 500 ppm NRLM fuel by June 1, 2007, including 19 refineries owned by small refiners.

^G Final Regulatory Impact Analysis, Control of Air Pollution from New Motor Vehicles: Tier 2 Motor Vehicle Emissions Standards and Gasoline Sulfur Control Requirements, U.S. EPA, December 1999.

^H "Highway Diesel Progress Review," U.S., EPA, June 2002, EPA420-R-02-016.

Table 5.3-1
Leadtime Projections Under the Tier 2 Gasoline Sulfur Program (years)

Project Stage	Naphtha/Gasoline Hydrotreating		More Major Refinery Modification (e.g., FCC Feed Hydrotreating)	
	Time for Individual Step	Cumulative Time ^a	Time for Individual Step	Cumulative Time ^a
Scoping Studies	0.5-1.0 ^b	0.5	0.5-1.0 ^b	0.5
Process Design	0.5	1.0	0.5-0.75	1.0-1.25
Permitting	0.25-1.0	1.25-2.0	0.25-1.0	1.25-2.0
Detailed Engineering	0.5-0.75	1.5-2.25	0.5-1.0	1.5-2.25
Field Construction	0.75-1.0	2.0-3.0	1.0-1.5	2.5-3.5
Start-up/Shakedown	0.25	2.25-3.25	0.25	2.75-3.75

^a Several of the steps shown can overlap.

^b Projected to begin before Tier 2 gasoline final rule.

This table contains leadtime projections for two distinctly different approaches to gasoline sulfur control. The first, naphtha hydrotreating, is more closely related to conventional distillate hydrotreating. In fact, a number of naphtha hydrotreating processes utilize fixed bed hydrotreating which is directly comparable to distillate hydrotreating. The second, FCC feed hydrotreating is more complex, extensive and costly. As discussed earlier in this chapter, some refiners might use FCC feed hydrotreating to facilitate the production of 500 ppm diesel fuel. However, this decision would likely have been tied to their compliance plans for the Tier 2 gasoline sulfur program, since FCC feed hydrotreating significantly reduces the sulfur content of gasoline, as well as diesel fuel. The Tier 2 gasoline sulfur standards are fully phased in for most refiners by 2006. Thus, it is highly unlikely that a refiner would just begin considering FCC feed hydrotreating as the result of this NRLM rule. We will therefore only focus on the portion of the table which addresses the leadtime for naphtha hydrotreating.

It should also be noted that the cumulative times listed in the table above are not simply the sum of the times for each step. Some steps overlap, in particular process design and permitting, permitting and detailed engineering, and detailed engineering and construction. The relationship between the time necessary for each step in the design and construction of naphtha and distillate hydrotreaters will be examined in detail. However, it would be useful first to review EPA's leadtime projections related to the 15 ppm highway diesel fuel cap.

5.3.2.2 15 ppm Highway Diesel Fuel Sulfur Cap

The rulemaking implementing the 15 ppm sulfur cap for highway diesel fuel did not evaluate the leadtime required for each individual step of the process. That rule provided 5.5 years of leadtime between promulgation and initial implementation. This amount of leadtime

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significantly exceeded that considered necessary to design and construct desulfurization equipment. This amount of leadtime was provided, since the timing of the 15 ppm sulfur cap was set primarily by the availability of highly efficient aftertreatment technology for diesel engines and not on refiners' ability to meet the 15 ppm standard.

EPA reviewed the progress that refiners were making towards complying with the 15 ppm highway diesel fuel cap in 2002. Part of this review included an assessment of the tasks which refiners had already completed and the length of time needed for those still remaining. The tasks considered were essentially the same as those listed in Table 5.3-1 above, with one exception. That was the inclusion of the need to develop a corporate strategy towards compliance in the initial step. This strategy involved a decision regarding the degree that the refiner was going to continue marketing highway diesel fuel and if so, whether he would comply with the 15 ppm standard initially in 2006 or later in 2010. However, diesel fuel can be sold to the highway or non-highway markets, involving compliance with very different sulfur standards. The flexibility afforded by the rule's temporary compliance option also gave refiners a choice of when they chose to comply with the 15 ppm cap. This issue didn't arise in the Tier 2 gasoline rule, since essentially all gasoline sold in the U.S. meets highway quality standards, and refiners have no other market for their gasoline feedstocks.

The results of the leadtime review are presented in the table below.

Table 5.3-2
Leadtime Assessment: Progress Review of 15 ppm Highway Diesel Fuel Cap

Project Stage	Time Allotted	Latest Start Date
Strategic Planning	0.25-2 years	-----
Planning and Front End Engineering ^a	0.5	Mid-2003
Detailed Engineering and Permits	1.0	Late 2003 - Early 2004
Procurement and Construction	1.25-2.5	October 2004
Commissioning and Start-Up	0.25-0.5	March 2006

^a Labeled Process Design in Table 5.3-1.

By grouping several of the process steps shown in Table 5.3-1 this later assessment reduces the overlap between the various steps considerably. The primary overlap still remaining is between detailed engineering and permits and procurement and construction. While construction cannot begin until permits have been obtained, procurement can proceed. This is often essential to any time constrained refining project, due to the long leadtimes needed to fabricate specialized equipment.

Because the progress review was conducted over a year after the rule was promulgated, EPA did not add up the times associated with each step to develop a range of cumulative time requirements. Instead, we focused on the dates by which refiners should have begun each step to

determine if they had indeed begun those steps which should have been started by the date of the assessment.

5.3.2.3 Leadtime Projections for Production of 500 ppm NRLM Diesel Fuel

We utilized the information for gasoline and highway diesel analyses to project the leadtime necessary for a wide spectrum of refiners to start producing 500 ppm NRLM diesel fuel. Beginning with strategic planning, refiners currently producing high sulfur diesel fuel/heating oil would have to decide whether they are going to continue producing high sulfur heating oil or produce 500 ppm NRLM diesel fuel. This would not likely be a difficult choice for many refiners, as the heating oil market would be too small in their area to support their entire production of high sulfur fuel. For those with a real choice, this step would likely involve discussions between the refining and marketing divisions of the firm, as well as with any common carrier pipelines used by the refiner. While many refiners would prefer to be able to observe their competition's choices and the relative production volumes and prices of 500 ppm NRLM diesel fuel and high sulfur heating oil before making a decision, this is not possible. Given this, it seems reasonable to allow a relatively short period of time, 3-6 months to arrive at a corporate decision to participate in the NRLM or heating oil markets.

Scoping and screening studies refer to the process whereby refiners investigate various approaches to sulfur control. These studies involve discussions with firms which supply desulfurization and other refining technology, as well as studies by the refiner to assess the economic impacts of various approaches to meeting the sulfur standard. In the case of distillate desulfurization, a refiner would likely send samples of their various distillate streams to the firms marketing desulfurization technology to determine how well each technology removed the sulfur from that particular type of distillate (e.g., sulfur removal efficiency, yield loss, hydrogen consumption, etc.).

Under the Tier 2 rule, we projected that 0.5-.1.0 years would be required to evaluate the various naphtha desulfurization technologies which were or soon to be available. This extensive period of time was deemed appropriate due to the wide range of technologies available. More importantly, however, was the fact that many of the new gasoline desulfurization technologies had not have been demonstrated in actual refinery applications by the time of the final rule. Refiners naturally desire as much demonstrated experience with any new technology as possible prior to investing significant amounts of capital in these technologies. We believed that at a minimum, refiners should have 6 months after the final rule to assess their situation with respect to the final sulfur control program and select their vendor and technology. Because the Tier 2 gasoline sulfur standards phased in over two years, some refiners had more time than others before their new desulfurization equipment had to be operational. Thus, we expected refiners to take as much time as they could afford to select the particular desulfurization technology which was optimum for their situation. Thus, there was really no upper limit to the amount of time for this step.

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The scoping and screening task which refiners would face with respect to the 500 ppm NRLM sulfur cap is both different and similar to the situation refiners faced with the Tier 2 gasoline program. The NRLM program would differ, because refiners had to choose between a wide variety of gasoline desulfurization technologies to comply with the Tier 2 sulfur standards. In contrast, above, we project that conventional hydrotreating would likely be the dominant choice for desulfurizing diesel fuel to 500 ppm in 2007. The similarity would exist, because refiners would have to consider how they are going to comply with the 15 ppm nonroad diesel fuel cap in 2010 when they design their conventional hydrotreater for 2007. While conventional hydrotreating is well understood, there are numerous ways to “conventionally hydrotreat” distillate. Variations exist in operating pressure, hydrogen purity, physical catalyst loading, etc. To avoid scrapping their conventional hydrotreaters after just three years, we project that the refiners building new conventional hydrotreating units for 2007 would plan these units to be easily revamped in 2010 to produce 15 ppm nonroad diesel fuel. Therefore, the specific conventional hydrotreating design selected for 2007 would have to mesh with their plan for 2010. At minimum, this would involve the selection of the operating pressure of the conventional hydrotreater, provision of physical space for additional equipment and the capacity of hydrogen supply and treatment lines. The selection of operating pressure is likely the most time critical, because of the long lead times involved in procuring pressure vessels. Some time for vendors to assess the performance of their 15 ppm technologies via pilot plants testing on specific refiners’ diesel fuel samples should be included.

Fortunately, this process has been underway for some time involving refiners’ highway diesel fuels. By mid-2004, this process should be essentially complete. Vendors’ should have ample capacity to test refiners’ NRLM diesel fuel samples, as well as have developed efficient approaches to translate test results into specific process designs. Thus, six months should be more than sufficient for refiners to make the necessary, critical choices about their conventional hydrotreater design. In fact, the selection of operating pressure could be made during the process design step, effectively reducing the amount of time to scoping and screening to three months.

The strategic decision to produce 500 ppm NRLM diesel fuel not only involves marketing, but an economic assessment of the cost of producing this fuel, both absolutely and relative to the competition. The scoping and screening studies are also not expensive to conduct. Refiners do not risk much to conduct them while they are still developing their corporate strategy. Also, the scoping and screening studies can go on concurrent with the development of a corporate strategy towards the rule. This means that the 3-6 months for strategic planning and the 3-6 months for scoping and screening can go on concurrently.

The time required for process design of a conventional distillate hydrotreater should be no greater than that for a naphtha hydrotreater or the revamp of a diesel fuel hydrotreater (i.e., six months in both Tables 5.3-1 and 5.3-2). In fact, the design of the naphtha hydrotreater may be more complex due to the desire to avoid too great a loss in octane from olefin saturation. Octane is not an issue with distillate hydrotreating. In general, the design of a grassroots distillate hydrotreater would be more complex than that of a revamp. However, here the revamp is to produce 15 ppm diesel fuel, a much more challenging task than producing 500 ppm diesel fuel.

Thus, six months should be sufficient for the process design of a 500 ppm NRLM unit. The cumulative time for the strategy, scoping and process design steps should range from 0.75-1.0 year, as the choice of distillate hydrotreating is clear.

Regarding permitting, EPA has taken a number of steps to help state/local permitting agencies to efficiently process refiners' requests for permits related to environmental-related projects such as these. Our experience with permits related to naphtha desulfurization indicates that 3-9 months would be a more realistic range, as opposed to the 3-12 months which was projected in the Tier 2 Final RIA. There, we identified the 12 month period as being a worse case scenario. Experience has confirmed this and we are not aware of any specific situations where obtaining a permit has taken this long and held up the project completion.

The detailed design and construction of a distillate hydrotreater could require some additional time relative to that for a naphtha hydrotreater due to the higher operating pressures required for distillate hydrotreating. Fewer firms fabricate higher pressure reactors and compressors. At the same time, less time should be required than required for a FCC feed hydrotreater. FCC feed hydrotreating usually occurs at even higher hydrogen pressures and involves much more cracking of large molecules into smaller ones. Additional equipment is necessary to handle the significant amount of gaseous product generated, etc. Interpolating between the times allocated for the detailed design and construction of a naphtha hydrotreater and a FCC feed hydrotreater results in 6-9 months to design and 12-15 months to construct a distillate hydrotreater. Cumulatively, the two steps would take 1-1.25 years from the time at which permits were obtained.

This range is about 3 months shorter than that projected in Table 5.3-2 for the 15 ppm highway diesel fuel rule. The difference on the high end is due to the fact that 2.5 years for construction does not appear to be necessary. This estimate was reasonable in the review of progress being made towards compliance with the 2007 highway diesel fuel rule due to the extensive amount of leadtime still available. For this to be typical, all refiners planning to produce 15 ppm highway diesel fuel would already be constructing their new or revamped hydrotreaters. Clearly this is not the case, yet refiners consider themselves on track to meet the standard. Thus, the time periods resulting from an interpolation of the naphtha and FCC feed hydrotreating estimates of Table 5.3-1 appear reasonable for producing 500 ppm NRLM fuel.

Finally, both the Tier 2 gasoline rule and 15 ppm highway diesel fuel review allocated 3 months for start up for naphtha, FCC feed and highway diesel fuel hydrotreaters. Allocating the same time period for starting a distillate hydrotreater should therefore be appropriate.

Table 5.3-3 presents the results of the above assessment.

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Table 5.3-3
Leadtime Projections for 500 ppm NRLM Diesel Fuel

Project Stage	Time for Individual Step	Cumulative Time
Strategic Planning	0.25-0.5	0.25-0.5
Scoping and Screening Studies	0.25-0.5	0.25-0.5
Process Design	0.5	0.75-1.0
Permitting	0.25-0.75	1.0-1.75
Detailed Engineering	0.5-0.75	1.5-2.25
Field Construction	1.0-1.25	2.0-3.0
Start-up/Shakedown	0.25	2.25-3.25

Assuming that the final rule is signed in April of 2004, this analysis indicates that some refiners should be able to produce 500 ppm NRLM fuel as early as July 2006. This coincides with the implementation of the 15 ppm highway diesel fuel cap and the ability to generate early 500 ppm NRLM credits. This analysis indicates that the last refiners should be able to produce 500 ppm NRLM fuel by July 2007. This is within a month of the implementation of the 500 ppm NRLM cap. Should any refiners be in the situation of needing this last month to produce 500 ppm NRLM fuel, they should be able to purchase early credits from other refiners and continue producing NRLM fuel until they are able to meet the 500 ppm cap.

5.3.2.4 Comparison with the 500 ppm Highway Diesel Fuel Program

The tasks refiners face in meeting the proposed 500 ppm NRLM cap is very similar to the task refiners faced with meeting the 500 ppm highway diesel fuel cap by October 1, 1993. The primary difference is that refiners have 10 years of experience producing 500 ppm diesel fuel commercially. This should only shorten the time required to prepare for the standard relative to 1993. The 500 ppm highway diesel rulemaking was promulgated in August 1990 and took effect on October 1, 1993.²⁸ Thus, that rulemaking provided 3 years and two months of leadtime, nearly identical to that provided by the NRLM proposal. Some price spikes occurred with the implementation of the 500 ppm highway diesel fuel standard. However, these were almost exclusively in California, where a 10 volume percent aromatics standard was implemented at the same time. Also, the October implementation coincided with the annual increase in refiners' distillate production related to winter heating oil use. At that time, the U.S. was one of the first nation's to require 500 ppm diesel fuel, so little commercial experience was available upon which to base designs. Today, refiners and technology vendors have over 10 years of commercial experience in producing 500 ppm diesel fuel. We have also shifted the implementation date away from the peak heating oil production season. Finally, the volume of highway diesel fuel affected was more than three times that being affected by today's proposed rule, causing greater stress on the engineering and construction industries than today's proposed program would cause.

Many refiners likely to produce 500 ppm NRLM diesel fuel in 2007 also have to invest to meet the Tier 2 gasoline sulfur standards and the 15 ppm highway diesel fuel cap. However, the Tier 2 program finishes phasing in in 2006 for most refiners. The 15 ppm highway diesel fuel likewise has a 2006 implementation date. This puts them at least one year ahead of the 500 ppm NRLM standard. This minimum offset of one year should ease the burden on any specific aspect of the process (e.g., raising capital funds, design personnel, construction personnel, etc.). The 1993 500 ppm highway diesel fuel cap also occurred in the midst of other fuel quality regulations. The phase 2 gasoline Reid vapor pressure standards and the oxygenated gasoline programs took effect in 1992, while the reformulated gasoline program began in 1995. Thus, the experience with the 500 ppm highway diesel fuel program appears to be a strong confirmation that the leadtime provided by today's proposal would be sufficient.

5.3.2.5 Small Refiners

Small refiners may need more time to comply with a sulfur control program. Small refiners generally have a more difficult time obtaining funding for capital projects, and must plan further in advance of when the funds are needed. We contracted a study of the refining industry which included assessing the time required for small refiners to obtain loans for capital investments. The simple survey revealed that small refiners would need two to three months longer than large refiners to obtain funding. If small refiners are forced to or prefer to seek funding through public means, such as through bond sales, then the time to obtain funding could be longer yet, by up to one third longer.²⁹ In addition, because of the more limited engineering expertise of many small refiners, the design and construction process for these refineries is relatively more difficult and time consuming. We also believe that the contractors which design and install refinery processing units will likely focus first on completing the more expensive upgrade projects for large refiners. Thus, the design and construction of desulfurization hardware for the small refiner would take longer as well. The three additional years being provided small refiners should be sufficient to compensate for these factors. This additional leadtime should provide not only enough time for these small refiners to construct equipment, but to also allow these refiners more time to select the most advantageous desulfurization technology. This additional time for technology selection will help to compensate for the relatively poor economy of scale inherent with adding equipment to a small refinery.

5.4 Feasibility of Distributing 500 ppm Sulfur Non-Highway Diesel Fuel in 2007 and 500 ppm Locomotive and Marine Diesel Fuel in 2010

There are two considerations with respect to the feasibility of distributing non-highway diesel fuels meeting the proposed 500 ppm sulfur standard. The first pertains to whether sulfur contamination can be adequately managed throughout the distribution system so that fuel delivered to the end-user does not exceed the specified 500 ppm maximum sulfur concentration. The second pertains to the physical limitations of the system to accommodate any additional segregation of product grades. These considerations are evaluated in the following Sections 5.4.3 and 5.4.4 of this Draft RIA.

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5.4.1 The Diesel Fuel Distribution System Prior to the Implementation of the Proposed 500 ppm Sulfur Program:

Prior to 1993, most number 2 distillate fuel was produced to essentially the same specifications, shipped fungibly, and used interchangeably for highway diesel engines, nonroad diesel engines, locomotive and marine diesel engines and heating oil (e.g., furnaces and boilers) applications. Beginning in 1993, highway diesel fuel was required to meet a 500 ppm sulfur cap and be segregated from other distillate fuels as it left the refinery by the use of a visible level of dye solvent red 164 in all non-highway distillate. At about the same time, the IRS similarly required non-highway diesel fuel to be dyed red (to a much higher concentration) prior to retail sale to distinguish it from highway diesel fuel for excise tax purposes (dyed non-highway fuel is exempt from this tax). This splitting up of the distillate pool necessitated costly changes in the distribution system to ship and store the now distinct products separately.

In some parts of the country where the costs to segregate non-highway diesel fuel from highway diesel fuel could not be justified, both fuels have been produced to the highway specifications. Diesel fuel produced to highway specifications but used for non-highway purposes is referred to as “spill-over.” It leaves the refinery gate and is fungibly distributed as if it were highway diesel fuel, and is typically dyed at a point later in the distribution system. Once it is dyed it is no longer available for use in highway vehicles, and is not part of the supply of highway fuel. Based on the most recent EIA data, roughly 15 percent of highway fuel is spillover, representing nearly a third of non-highway consumption.

When the 15 ppm highway diesel fuel standard takes effect in 2006, an additional segregation of the distillate pool is anticipated. Since up to 20 percent of the highway diesel fuel pool is allowed to remain at 500 ppm until 2010, in some portions of the country as many as three grades of distillate may be distributed; 15 ppm highway, 500 ppm highway, and high sulfur for all non-highway uses. The final highway diesel rule estimated that 500 ppm diesel fuel would be present in 40 percent of the fungible fuel distribution system including the Northeast, parts of the Midwest and in and adjacent to the concentration of refineries in PADD 3.

5.4.2 Summary of the Proposed 500 ppm Sulfur Standards

The proposed sulfur standards generally cover all the diesel fuel that is used in mobile applications but is not already covered by the previous standards for highway diesel fuel. This fuel is defined primarily by the type of engine which it is used to power, nonroad, locomotive, and marine diesel engines. In shorthand, this fuel will be referred to as NRLM fuel.

NRLM fuels typically include:

- 1) Any number 1 and 2 distillate fuels used in or intended to be used in land-based nonroad, locomotive or marine diesel engines,
- 2) Any number 1 distillate fuel (e.g., kerosene) added to such number 2 diesel fuel, e.g., to improve its cold flow properties and

3) Any other fuel used in or blended with diesel fuel for use in nonroad, locomotive, or marine diesel engines that has comparable chemical and physical characteristics.

The proposed sulfur standards would not apply to:

- 1) Number 1 distillate fuel used to power jet aircraft,
- 2) Number 1 or number 2 distillate fuel used for other purposes, such as to power stationary diesel engines or for heating,
- 3) Number 4 and 6 fuels (e.g., bunker or residual fuels, IFO Heavy Fuel Oil Grades 30 and higher, ASTM DMB and DMC fuels), and
- 4) Any fuel used to power equipment for which a national security exemption has been approved.

As in the recent highway diesel rule, in those cases where the same batch of kerosene is distributed for two purposes (e.g., as kerosene to be used for heating and to improve the cold flow of number 2 nonroad diesel fuel), that batch of fuel would have to meet the standards being proposed today for nonroad diesel fuel. An alternative compliance approach would be to produce and distribute two distinct kerosene fuels. Under such an approach, one batch would meet the proposed sulfur standards and could be blended into number 2 NRLM diesel fuel. The other batch would only have to meet any applicable specifications for heating fuel.

We are proposing to restrict the sulfur content of NRLM fuel nationwide to no more than 500 ppm beginning in 2007. These provisions mirror controls on highway diesel fuel to 500 ppm in 1993.³⁰ Refiners and importers could comply with the proposed requirement by either producing NRLM fuel at or below 500 ppm, and/or by obtaining credits under the proposed averaging banking and trading (ABT) provisions. The 2007 deadline for meeting the proposed 500 ppm NRLM sulfur standard would not apply to refineries covered by special hardship provisions for small refineries. In addition, a different schedule might apply for any refineries that might be approved under the proposed general hardship provisions.

We are proposing that high sulfur NRLM diesel fuel which remains after June 1, 2007 due to the small refiner and fuel ABT provisions could be commingled with 500 ppm NRLM diesel fuel after it has been dyed to the IRS specifications until June 1, 2010. Thus, at some points in the distribution system, NRLM fuel higher than the 500 ppm standard would remain until it is precluded from production beginning June 1, 2010. The proposed 15 ppm sulfur standard for nonroad diesel fuel would take effect in June 1, 2010.

Under the proposed 500 ppm NRLM program, heating oil would be allowed to have its sulfur level remain uncontrolled; limited only by various state regulations. Thus, while NRLM is commonly distributed today with heating oil, after implementation of the proposed sulfur standards, these two grades of fuel would have to be distributed separately. To ensure that high-sulfur diesel fuel manufactured for the heating oil market would not be used in nonroad, locomotive, or marine applications, we are proposing that heating oil be injected with a fuel marker before it leaves refinery. After June 1, 2010, the fuel standards situation is simplified

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considerably and the fuel program structure can therefore also be simplified. We are proposing that after June 1, 2010 high sulfur diesel fuel no longer be permitted to be used in any NRLM equipment. The only high sulfur distillate remaining in the market should be heating oil. Heating oil would have to be kept segregated and preventing its use in NRLM equipment could be enforced on the basis of sulfur level, avoiding the need for a unique marker to be added to heating oil. Thus, we are proposing that the marker requirement for heating oil expire after June 1, 2010.

After June 1, 2010, we are proposing that locomotive and marine diesel fuel would be allowed to remain at the 500 ppm level. Under the proposed small refiner hardship and fuel credit provisions, we would also allow the continued production and use of 500 ppm nonroad diesel fuel for a limited time past June 1, 2010. To ensure that adequate quantities of 15 ppm diesel are produced, we are proposing the use of a marker to segregate locomotive and marine diesel fuel from 500 ppm nonroad diesel fuel beginning June 1, 2010. Since use of the marker in heating oil is no longer required, we are proposing that the same marker used for heating oil from June 1, 2007 through 2010 be the marker used in locomotive and marine diesel fuel beginning June 1, 2010. We propose that the marker would be required to be added at the refinery gate just as visible evidence of the red dye is required today, and fuel containing the marker would be prohibited from use in any nonroad application.

Beginning June 1, 2014, after all small refiner and credit provisions have ended, the 500 ppm locomotive and marine standard could be enforced based on sulfur level throughout the distribution system and at the end-user. Therefore, there would no longer be any need for a marker. Consequently, we are proposing that after May 31, 2014 there would be no marker requirement and the different grades of fuel, 15 ppm, 500 ppm, and high sulfur would merely have to be kept segregated in the distribution system.

We are proposing that the current requirement that non-highway distillate fuels be dyed at the refinery gate be made voluntary effective June 1, 2006. The IRS requirement that non-highway fuel be dyed prior to sale to consumers to exempt it from excise taxes will still apply.

There are two considerations with respect to the feasibility of distributing non-highway diesel fuels meeting the proposed 500 ppm sulfur standard. The first pertains to whether sulfur contamination can be adequately managed throughout the distribution system so that fuel delivered to the end-user does not exceed the specified 500 ppm maximum sulfur concentration. The second pertains to the physical limitations of the system to accommodate any additional segregation of product grades. These considerations are evaluated in the following Sections 5.4.1 and 5.4.2 of this Draft RIA.

5.4.3 Limiting Sulfur Contamination

With respect to limiting sulfur contamination during distribution, the physical hardware and distribution practices for non-highway diesel fuel do not differ significantly from those for current highway diesel fuel. Therefore, we do not anticipate any new issues with respect to

limiting sulfur contamination during the distribution of non-highway fuel that would not have already been accounted for in distributing highway diesel fuel. Highway diesel fuel has been required to meet a 500 ppm sulfur standard since 1993. Thus, we expect that limiting contamination during the distribution of 500 ppm non-highway diesel engine fuel can be readily accomplished by industry.

5.4.4 Potential Need for Additional Product Segregation

During the first step of today's program, we anticipate that 500 ppm non-highway diesel engine fuel would be distributed in fungible batches with 500 ppm highway diesel fuel through the distribution system to the terminal level. When the second step of the proposed program would require nonroad diesel fuel to meet a 15 ppm sulfur standard all highway fuel would also be required to meet a 15 ppm standard. Thus a large fraction of the potential 500 ppm diesel fuel pool would disappear. Since marked 500 ppm locomotive and marine diesel fuel would be a relatively small volume product, we anticipate that in most parts of the distribution system it would not be carried as a separate product in the fungible distribution system. Therefore we anticipate that most shipments of 500 ppm locomotive and marine fuel would be from refinery racks or other segregated shipments directly into end-user tankage. Any diesel fuel supplied off the fungible supply system for locomotive and marine uses would therefore likely be spillover from 15 ppm supply.

The proposed non-highway sulfur program would require the use of a unique fuel marker in heating oil to differentiate it from other non-highway diesel engine fuels that would be subject to today's proposed sulfur standards. Under the proposed program, heating oil would be injected with a marker at the refinery and segregated throughout the fuel distribution system to the end-user. The heating oil marker requirement would expire after 2010, to be replaced with the requirement that 500 ppm diesel fuel destined for locomotive and marine use contain the marker previously used in heating oil. The presence of the marker raises the potential for additional product segregation needs in both 2007 and 2010.

The proposed application of different sulfur standards to portions of the non-highway distillate pool based on end-use also raises concerns regarding the potential need for additional product segregation.

Currently, distillate fuel for all non-highway uses is typically drawn from a single pool that meets the most stringent specifications for any non-highway use. For example, it is our understanding that nearly all heating oil meets the cetane specification for non-highway diesel engine use despite the lack of applicability of a cetane specification for distillate fuel used as heating oil. This is because fuel manufacturers and marketers have found that the potential savings from manufacturing a low cetane heating oil are typically outweighed by the additional costs of segregating an additional heating-oil-only product throughout the distribution system.

We anticipate that the significant cost of desulfurizing non-highway diesel engine fuel to meet today's proposed sulfur standards would provide a strong incentive for the fuel distribution

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system to evaluate whether the additional costs of distributing non-highway distillate fuels of different sulfur specifications is economically justified. This situation is analogous to that faced by industry after the implementation of the current EPA requirement in 1993 that highway diesel fuel have a sulfur content of less than 500 ppm.

The Internal Revenue Service (IRS) requirement that diesel fuel used in non-highway engines be dyed before it leaves the terminal to indicate its non-taxed status also raises concerns about the potential need for additional product segregation under the proposed NRLM sulfur program. Fuel that meets highway diesel specifications but is destined for the non-highway market can leave the terminal undyed provided that the tax is paid. Non-highway users of such fuel can then apply to the federal and applicable state revenue offices for a refund of the highway taxes paid on the fuel. In areas of the country where only 500 ppm diesel fuel is currently available by pipeline, most bulk plant operators nevertheless maintain dual tankage for dyed and undyed 500 ppm diesel fuel to meet the demands of their customers for highway-tax-free non-highway diesel fuel. Such bulk plant operators currently receive dyed diesel fuel by truck from local refineries. Thus, the IRS non-highway diesel dye requirement may result in a strong incentive for parties in the fuel distribution system downstream of the terminal to maintain segregated pools of undyed highway and dyed non-highway diesel fuel that differ in no other respect than the presence of dye (both after the implementation of the 15 ppm highway diesel requirements in 2007, and the proposed requirements for NRLM fuel).

We expect that after the implementation of the proposed NRLM standards most bulk plant operators would request that the terminal (or refinery rack) dye 500 ppm fuel destined for sale into the non-highway market, so that they continue their current practice of offering untaxed diesel to their non-highway customers. This raises issues of available tankage.

The following discussion evaluates the potential need for additional product segregation for each segment of the distribution system from the refinery through to the end-user due to the implementation of the proposed 500 ppm non-highway diesel sulfur standard.

Refineries:

Due to economies of scale involved in desulfurization, we expect that most individual refineries would choose to manufacture a single or perhaps in some case two sulfur grades of diesel fuel. We do not anticipate that individual refineries would produce substantial quantities of all the different diesel fuel sulfur grades (15 ppm highway fuel, 500 ppm, and heating oil). We do not anticipate the need for additional product segregation at refineries. As discussed above, today's proposal would allow highway and nonroad diesel fuels to be shipped fungibly until NRLM fuel is dyed for IRS excise tax purposes. Therefore, today's proposed sulfur standards for NRLM diesel fuel would not require refiners to put in new product storage tanks to handle these fuels. The proposed marker requirements for heating oil from 2007-10 and for locomotive and marine diesel fuel from 2010-14 would also not cause the need for additional product segregation at the refinery. We expect that refiners would inject the marker into the fuel stream as it leaves their facility. Since the dye requirement for these fuels is removed at the refinery gate, they should be able to modify their existing additive injection hardware to satisfy

this need. The ability of a refinery to sell diesel fuel directly from the would mean that they could market dyed and marked fuel with out the need for additional tankage. The dye and marker could be injected as the fuel is loaded into the tank truck from the rack.

A limited number of refiners would be allowed to produce high-sulfur NRLM until 2010. We expect that such fuel would be distributed via segregated means from the refinery to the end-user. Thus, we do not expect that such fuel would result in the need for additional tankage.

There will be no physical differences between 500 ppm highway and 500 ppm NRLM produced by refiners. The distinction between the two fuels is only made for accounting purposes to ensure compliance with limitations on the volume of 500 ppm highway diesel fuel that can be produced by refiners (under the highway diesel final rule) is complied with.

Pipelines:

Under today's proposal, pipeline operators would ship only a single 500 ppm diesel fuel to be later directed to either the highway or NRLM market. We project that only the 40 percent of pipelines that the highway diesel rule projected would carry 500 ppm highway diesel fuel would be the pipelines that elect to 500 ppm diesel fuel after the implementation of the proposed NRLM diesel fuel program. Therefore, we do not expect that the proposed 500 ppm sulfur standards would necessitate the need for additional product segregation in the pipeline distribution system.

There is no physical separation between product batches shipped by pipeline. When the mixture that results at the interface between two products that touch each other in the pipeline can be cut into the one of these products, it is referred to as product downgrade. When the mixture must be removed for reprocessing, it is referred to as transmix. Given that the pipelines that carry 500 ppm diesel fuel would be able to combine batches of 500 ppm non-highway diesel fuel with batches of 500 ppm highway diesel fuel, we do not expect that today's program would result in an increase the volume of product downgrade or transmix volumes. To the contrary, there may be some opportunity for improved efficiency because of the increase in batch sizes shipped by pipeline. This potential benefit could be significant given that the volume of 500 ppm NRLM shipped by pipeline would represent a sizeable fraction of the total 500 ppm diesel fuel volume.

We also do not expect that the marker requirement for heating oil would result in an increased need for product segregation in the pipeline or an increase in product downgrade or transmix volumes. After the implementation of the proposed 500 ppm standard for nonroad, locomotive, and marine fuel, we project that significant volumes of heating oil would continue to be present only in the fuel distribution system that supplies the Northeast, limited adjoining parts of the Midwest, and the Pacific Northwest.

We believe that only in these areas, would the demand for heating oil be sufficiently large to justify the continued distribution of high-sulfur diesel fuel once nonroad, locomotive, and marine diesel fuel is removed from the potential high-sulfur diesel pool. Therefore, heating oil would

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not be present in pipeline systems that supply areas outside of the Northeast, limited adjoining parts of the Midwest, and the Pacific Northwest. The pipelines that we project would handle heating oil after the implementation of today's proposal are those that we projected would also be carrying 500 ppm highway diesel fuel from 2006-10. Therefore, these pipelines would already have facilities to also carry 500 ppm NRLM in 2007 (in the pipeline there is no physical distinction between 500 ppm highway and 500 ppm NRLM diesel fuel). Consequently, we do not expect that the heating oil marker requirement would result in additional product segregation by pipeline.

We anticipate that in some cases high sulfur fuel will be sold directly from refinery racks throughout the country. In addition, some terminals outside of these areas may market limited quantities of high-sulfur diesel fuel that was generated in the pipeline during the distribution of 15 ppm diesel fuel. We expect that such fuel would be marketed directly from the terminal to the end user. The limited additional tankage at the terminal was accounted for under the highway program.

The situation for pipeline operators after 2010 when the marker must be used in locomotive and marine fuel would be somewhat different, but is still not expected to result in any new product segregation needs. Under today's proposal, all nonroad diesel fuel would be required to meet a 15 ppm sulfur standard in 2010 except for limited quantities of small refiner and credited fuel that could remain at 500 ppm for a limited additional time. We expect that this nonroad fuel which remains at 500 ppm after 2010 would be distributed by the refiner to the end-user directly. Therefore, its presence in the distribution system would not result in the need for additional product segregation. The highway diesel program also requires that all highway diesel fuel meet a 15 ppm sulfur standard beginning in 2010. Consequently, the only 500 ppm diesel fuel possibly remaining in the fungible distribution system would be marked 500 ppm locomotive and marine diesel fuel. We expect that pipelines that carried 500 ppm diesel fuel prior to 2010 would be the only pipelines that might choose to carry marked 500 ppm locomotive and marine diesel fuel. Therefore, the equipment that had been used to handle unmarked 500 ppm diesel fuel prior to 2010 would be switched to handling marked 500 ppm diesel fuel after 2010. Due to the reduction in the total potential 500 ppm diesel pool beginning in 2010, it is likely that a number of pipelines will no longer find it economical to carry 500 ppm as well as 15 ppm diesel fuel. We are projecting that most pipelines would elect not to carry 500 ppm diesel fuel and would carry only 15 ppm diesel fuel after 2010. This could result in some overall simplification of the diesel distribution system. Another factor that mitigates any potential need for additional product segregation as a result of the marker requirement for locomotive and marine diesel fuel is that locomotive and marine diesel fuel is often distributed through a segregated distribution system.¹ Based on the above discussion, we anticipate that the locomotive and marine diesel fuel marker requirement would not result in an increased need for product segregation in the pipeline or an increase in product downgrade or transmix volumes.

¹ In addition, we understand that marine diesel fuel is often shipped by barge from the refiner to the end user. This is also the case for locomotive diesel fuel when there is an opportunity for waterborne transportation.

Terminals:

The product segregation needs at terminals are directly affected by the range of products that they receive by pipeline. Thus, the discussion regarding the potential impacts of today's proposed rule on terminal operators closely parallels the preceding discussion on the potential impacts on pipeline operators. The proposed allowance that highway and non-highway diesel fuel meeting the same sulfur specification could be shipped fungibly until non-highway diesel fuel must be dyed to indicate its non-tax status obviates the need for additional product segregation at the terminal that might otherwise result from today's proposed sulfur standards. We expect that terminal operators would store non-highway and highway diesel fuel meeting the same sulfur specification in the same tank.

We do not anticipate that the proposed marker requirement for heating oil would require any additional storage tanks. As discussed above, in most of the country, we do not anticipate heating oil would continue to be carried as a separate grade in the fungible distribution system after the implementation of the proposed NRLM sulfur standards. As a result, 500 ppm fuel could take the place of the current tank of high sulfur fuel. In the areas where we project heating oil would continue to be distributed, 500 ppm highway fuel is also projected to be distributed. Consequently, marked heating oil can remain in its high sulfur tank, and the existing 500 ppm highway tank can service both highway and NRLM uses.

Bulk Plants:

Bulk plants are secondary distributors of refined petroleum products. They typically receive fuel from terminals and distribute fuel in bulk by truck to end users. Consequently, while for highway fuel, bulk plants often serve the role of a fuel distributor, delivering fuel to retail stations, for nonroad fuel, they often serve the role of the retailer, delivering fuel directly to the end-user. Bulk plants represent the one point in the distribution system where we anticipate some additional tankage would likely be added as a result of today's proposal. However, we project that only a small subset of the bulk plants would be faced with the choice of adding additional tankage. In most areas of the country, a distinct grade of heating oil would no longer be carried, and bulk plant operators could simply switch the tank that they previously devoted to high sulfur service to 500 ppm NRLM and heating oil service in 2007.

In areas where heating oil is anticipated to remain as a separate grade, we anticipate that bulk plants will face the choice of adding a new tank and perhaps demanifolding their delivery truck in order to distribute dyed 500 ppm NRLM diesel fuel in addition to dyed and marked heating oil. In this context demanifolding refers to the process of separating a single storage tank on a delivery tank truck to make two compartments. Some bulk plants that face the choice of installing the facilities to allow additional product segregation may find the cost of a new storage tank and demanifolding their delivery truck is too high, or may not have the space or capability to add new tank. However, such bulk plants would have other options. If they own another bulk plant facility in the area, they may choose to optimize use of available tankage by carrying one of the grades at each facility. Even if they do not own another facility, they may be able to work out a similar arrangement with a terminal or other bulk plant in the area. They could choose to supply heating oil only during the winter months, and supply NRLM during the summer months

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to both markets. Finally, they could simply choose not to distribute one of the fuel grades. (For example, either sell NRLM for both uses or sell only heating oil and allow other fuel distributors in the area to satisfy the NRLM market.) We anticipate that approximately 1,600 bulk plants would face the decision of adding new tankage or finding some other means of continuing to serve both heating oil and nonroad markets. This is the number of bulk plants that we project would be located in the areas of the country where heating oil would be continued to be carried by the fungible distribution system after the implementation of the proposed NRLM standards and where 500 ppm fuel would also be carried. Of these, we expect no more than 1,000 would choose to install a new tank.³¹

We do not anticipate that bulk plants would invest to carry locomotive and marine fuel as a separate grade in 2010. Therefore, unless a bulk plant had existing tankage available or supplied a majority of its fuel to locomotive and marine uses, this grade would likely be limited to refinery and terminal distribution. This is how the bulk of the distribution of locomotive and marine diesel fuel occurs today.

Based on the above discussion, we believe that the potential impacts of today's proposed rule on the distribution system due to the need for additional product segregation would be minimal and easily accommodated by industry. Please see 7.3 of this Draft RIA for a discussion of the increased distribution costs associated with the need for additional segregation at bulk plants.

5.5 Feasibility of Producing 15 ppm Sulfur Nonroad Diesel Fuel in 2010

5.5.1 Expected use of Desulfurization Technologies for 2010

Like the 500 ppm sulfur standard for 2007, we considered a number of different criteria to project which desulfurization technologies which would be used to comply with a 15 ppm nonroad sulfur cap standard for 2010. The criteria we considered included: 1) the time which refiners will have to choose a new technology, 2) whether the technology would be available for 2010 and if the technology is available, how proven it is, 3) whether the technology is cost-competitive by comparing it to other technologies, 4) whether the technology is available from an industry-trusted vendor which has proven itself to the industry by providing other successful refining technologies, particularly if the vendor has proven itself in the U.S., and 5) whether the vendor has the capability to meet the demands of the industry.

Unlike the 2007 standard, refiners would have plenty of time to evaluate the various desulfurization technologies and to choose which one would be best suited for their particular application. As stated above, we believe that this rule would be promulgated sometime in early 2004, thus, refiners will have 6 years between when the rule is promulgated and when the rule takes effect. Therefore, refiners would not be constrained in any way when making their decisions so this particular issue did not figure into our choice of the technologies which they would use.

Next, we considered whether a technology would be expected to be available for 2010. Of

course, conventional hydrotreating is available as it has been used in a number of applications to comply with a very stringent sulfur standard like a 15 ppm sulfur standard as described above. In addition, many refiners are expected to use conventional hydrotreating to comply with the highway diesel 15 ppm cap which applies in 2006. This would give refiners some experience with this technology prior to making a decision on what technology to use. Phillips is targeting to have their diesel fuel commercial demonstration unit up and running in early 2004 and they are expecting to have numerous gasoline desulfurization units starting up in 2004 as well. The operation of these units for two or more years prior to having to make their decisions for 2010 would give refiners confidence that these units can operate effectively over a significant period of time.

Linde already has a diesel fuel hydrotreating commercial demonstration unit operating which is a revamp of a 500 ppm highway diesel fuel desulfurization unit (installed before the existing highway hydrotreater). This unit demonstrates that the technology does indeed work for treating untreated diesel fuel to 500 ppm, however, refiners would like to see the technology demonstrated over the 500 ppm to 15 ppm sulfur reduction interval as well. With the 15 ppm highway diesel fuel sulfur standard taking effect in 2006, Linde should be able to demonstrate its technology for the 500 ppm to 15 ppm sulfur reduction interval. Thus, refiners that would be seeking to comply with the proposed 15 ppm sulfur nonroad standard should be able to see at least one, and probably more, examples of the Linde Isotherming process operating to desulfurize diesel fuel down to 15 ppm.

The oxidation and extraction technologies by Petrostar and Unipure do not have units operating now, but are projecting to have commercial demonstration units operating by 2006. However, an oxidation and extraction unit which begins operation in 2006 would not provide two years of operations for interested nonroad refiners prior to when they will have to choose their technology for 2010. Similarly, biodesulfurization is not expected to have a commercial demonstration unit operating before 2006.

Another issue which refiners would consider is the cost of installing and operating these various technologies. Biodesulfurization has not yet developed detailed desulfurization costs for their process. Of the oxidation and extraction technologies, Unipure did provide us with desulfurization cost information based on testing at their laboratory, and that information shows that it might be cost competitive with conventional hydrotreating. Petrostar, however, has not yet provided us with desulfurization information. Phillips also has provided us with diesel fuel desulfurization cost information from their pilot plant which is backed up by the success which they have had with their commercial gasoline desulfurization unit (see Chapter 7.2). That technology seems to be less expensive than conventional hydrotreating, it appears to be suited primarily for desulfurizing low sulfur diesel fuel down to very low sulfur values rather than for desulfurizing higher sulfur feedstocks. As a result, its primary usefulness would be for refiners revamping from compliance with 500 ppm in 2007 to 15 ppm in 2010. Finally, Linde provided us diesel fuel desulfurization cost information which is based on their pilot plant and their engineering cost estimates for the commercial demonstration unit at the Giant refinery. The Linde process seems to be less expensive than conventional hydrotreating and is capable of

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desulfurizing high sulfur feedstocks down to 15 ppm (see Chapter 7.2).

We next evaluated whether each diesel fuel desulfurization technology vendor is equipped to provide preliminary engineering and support the installations of its technology to a significant part of the refining industry. Conventional hydrotreating is provided by numerous vendors (Akzo Nobel, Criterion, Haldor Topsoe, IFP, and UOP) the majority of which manufacture their own line of diesel desulfurization catalysts. Also, these vendors supported the installation of many diesel fuel hydrotreaters to meet the 500 ppm highway diesel fuel sulfur standard which went into effect in 1993, and will be working with refiners to meet the very stringent 15 ppm highway diesel fuel sulfur standard which begins to take effect in 2006. Thus, conventional desulfurization technology is poised to make a significant contribution.

Phillips licenses several different technologies to refiners now, including its S-Zorb gasoline desulfurization technology and an alkylation technology, and has licensed refining technologies for over 60 years. Phillips has a robust research and development staff and also an engineering staff to support the licensing of its S-Zorb technology.

Linde licenses several different technologies now including sulfur and olefins recovery, natural gas processing, hydrogen production, reforming, air separation, and of course the Isotherming process for desulfurizing diesel fuel. Linde has a large engineering and design department which has been active for over 30 years, and now Linde has an alliance with Roddy Engineering for additional engineering support. Thus, Linde is capable of supporting its desulfurization technology for a significant penetration into the U.S. refining industry.

The oxidation and extraction technologies are being developed by two separate entities, one being Unipure and the other Petrostar. Unipure is associated with Texaco and Mustang engineering. Thus, Unipure potentially has both research and development and engineering support for its technology. Petrostar is affiliated with DeGussa Catalysts which can provide research and development support. Neither of these technologies have yet been licensed for desulfurizing diesel fuel.

After evaluating the various criteria for each technology and comparing across technologies, we developed a projection for the mix of technologies which would be used in 2010 for complying with the 15 ppm cap standard. Since refiners will have plenty of time to sort through the various technologies, we believe that the leadtime issue would have no bearing on refiners ability to choose an advanced desulfurization technology. Whether a technology will have accumulated at least two years of commercial experience is an important issue for the oxidation and extraction and biodesulfurization technologies as these technologies have not announced that their technology is available for licensing yet, and are not expected to have a commercial demonstration unit operating for at least two years. Thus, while the Petrostar, Unipure desulfurization technologies might be selected by refiners for 2010, we are not including their technologies in our projected mix of technologies.

This leaves conventional hydrotreating, Phillips S-Zorb and Linde Isotherming. Obviously,

conventional hydrotreating will have the most refining experience due to refiners' experience earlier on and also due to production of 15 ppm highway fuel for 2006. However, both S-Zorb and Isotherming are expected to have one or more diesel fuel desulfurization commercial demonstration units operating for over two years. Both the S-Zorb and the Isotherming hydrotreating processes are expected to be lower in cost than conventional hydrotreating providing a strong incentive to refiners which are seeking to lower their refining margins. Also both Phillips and Linde have research and development and engineering capacity to support their processes, although not the same level of support as the multiple conventional hydrotreating firms. After comparing these various criteria, we decided that the lower cost of S-Zorb and Isotherming would be the most important driver for these technologies. Thus, we believe that S-Zorb and Isotherming would each be used to a greater extent than conventional hydrotreating. We project that S-Zorb and Isotherming would each capture 40 percent of the nonroad desulfurization market by 2010, while conventional hydrotreating would capture the remaining 20 percent of the nonroad desulfurization market.

It was also necessary to estimate the technology mix for other potential years for a 15 ppm sulfur cap standard per the various other alternative fuel options being considered. The relative cost of these technologies is not estimated to change, however, the degree to which refiners have confidence in each of these technologies would change over time. In the years before 2010, refiners would not be expected to place as much trust with S-Zorb and Isotherming because there would be less time for these technologies to be proven to refiners. In 2009 we project that S-Zorb and Isotherming would each capture 30 percent of the nonroad desulfurization market. Similarly, we project that S-Zorb and Isotherming each capture 20 percent of the nonroad desulfurization market in 2008. For 2010, we project that S-Zorb and Isotherming would each capture 40 percent of the desulfurization market. Finally, in 2012 and later, we project that S-Zorb and Isotherming would each capture 50 percent of the nonroad desulfurization markets.

5.5.2 Leadtime Evaluation

More leadtime would be required to meet a 15 ppm diesel fuel cap than a 500 ppm cap. The additional time would primarily involve the scoping and screening step, as the technology to achieve a 15 ppm sulfur cap is just being demonstrated on a commercial scale and a number of advanced technologies promising lower costs are under development. This additional time might be on the order of a few months, while the 2010 implementation date for the 15 ppm cap provides an additional three years of leadtime. Therefore, the amount of leadtime available for the 15 ppm cap on nonroad diesel fuel should be more than sufficient for refiners to prepare for producing this fuel.

Of more interest is the interaction between the timing of the 15 ppm cap on highway diesel fuel and that proposed for nonroad diesel fuel. The time periods listed in Table 5.3-3 indicate that refiners would have to start their process designs 2.0-2.75 years before first producing 15 ppm diesel fuel and complete these process designs 1.5-2.25 years before the implementation date. This means that process design should begin by September 1, 2007 to June 1, 2008, and be completed by March 1 to December 1, 2008. This would provide refiners planning to produce 15

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ppm nonroad diesel fuel with 15-24 months of experience by highway diesel fuel refiners before initiating their process design. Given that catalyst cycles last 2-3 years, refiners could observe the performance of catalysts used to produce 15 ppm highway diesel fuel for one half to two thirds of a full cycle before having to begin their process design for nonroad. While most of the units producing highway diesel fuel in 2006 are expected to use conventional hydrotreating, as discussed above, we also expect both Linde Isotherming and Phillips' SZorb processes to be used to commercially produce 15 ppm diesel fuel by the end of 2004. Thus, refiners planning for 2010 would be able to observe these newer processes for more than 3 years prior to their selection of vendor and technology. This should be sufficient to overcome any uncertainty about their performance. Overall, the available leadtime should allow all refiners to take advantage of the operating performance of the highway units and minimize their costs.

5.6 Feasibility of Distributing 15 ppm Sulfur Nonroad Diesel Fuel in 2010

The same two criteria apply regarding the evaluation of the feasibility of distributing 15 ppm sulfur nonroad diesel fuel as apply regarding the feasibility of distributing 500 ppm sulfur non-highway diesel fuel: limiting sulfur contamination, and the potential need for additional product segregation. However, concerns related to limiting contamination during the distribution of 15 ppm nonroad diesel fuel are more substantial given that industry is just now in the process of learning how to accomplish the task of distributing 15 ppm diesel fuel in the fungible distribution system in preparation for compliance with the 15 ppm sulfur specification for highway diesel fuel in 2007. These considerations are evaluated in the following 5.6.3 and 5.6.4 of this Draft RIA.

5.6.1 The Diesel Fuel Distribution System Prior to the Implementation of the Proposed 15 ppm Nonroad Diesel Sulfur Program

Refer to 5.4 of this Draft RIA for a discussion of the diesel fuel distribution system prior to the implementation of the proposed 500 ppm NRLM sulfur program. Section 5.4 also contains a discussion of the potential effects on the distribution system of the implementation of the 500 ppm NRLM program in 2007 and the continuance of the 500 ppm sulfur standard for locomotive and marine diesel fuel past 2010. The discussion in section 5.4 provides the baseline against which the potential effects on the distribution system from the implementation of the proposed 15 ppm nonroad diesel sulfur standard in 2010 are evaluated.

5.6.2 Summary of the Proposed 15 ppm Nonroad Diesel Sulfur Standard

We are proposing to restrict the sulfur content of nonroad diesel fuel nationwide to no more than 15 ppm beginning in 2010. This proposed requirement mirrors the 15 ppm sulfur requirement for highway diesel fuel which will become effective in 2006.³² As with the 500 ppm NRLM standard that we are proposing, refiners and importers could comply with the proposed 15 ppm nonroad standard by either physically producing 15 ppm fuel or by obtaining sulfur credits. Also similar to the proposed 500 ppm NRLM standard, the deadlines for meeting the 15 ppm nonroad sulfur standard would not apply to refineries covered by special hardship provisions for small refineries. In addition, a different schedule might apply for any refineries that

might be approved under the proposed general hardship provisions. Only 15 ppm diesel fuel would be permitted for use in 2011 and later model year nonroad equipment. As discussed in 5.4, locomotive and marine diesel fuel would continue to be subject to the proposed 500 ppm sulfur standard after 2010.

In order to allow for a smooth and orderly transition of diesel fuel in the distribution system to 15 ppm, we are proposing that parties downstream of the refineries be allowed a small amount of additional time to turnover their tanks to 15 ppm. We are proposing that at the terminal level, nonroad diesel fuel would be required to meet the 15 ppm sulfur standard beginning July 15, 2010. At bulk plants, wholesale purchaser-consumers, and any retail stations carrying nonroad diesel, this fuel would have to meet the 15 ppm sulfur standard by September 1, 2010. The proposed transition schedule for compliance with the 15 ppm standard at refineries, terminals, and secondary distributors are the same as those allowed under the recently promulgated highway diesel fuel program.

5.6.3 Limiting Sulfur Contamination

In the highway diesel rule, EPA acknowledged that meeting a 15 ppm sulfur specification would pose a substantial new challenge to the distribution system. Refiners, pipelines and terminals would have to pay careful attention to and eliminate any potential sources of contamination in the system (e.g., tank bottoms, deal legs in pipelines, leaking valves, interface cuts, etc.) In addition, bulk plant operators and delivery truck operators would have to carefully observe recommended industry practices to limit contamination, including things as simple as cleaning out transfer hoses, proper sequencing of fuel deliveries, and parking on a level surface. The necessary changes to distribution hardware and practices and the associated costs are detailed in the RIA to the highway diesel final rule.³³

We are continuing to work with industry to ensure a smooth transition to the 15 ppm sulfur standard for highway diesel fuel. In November of 2002, a joint industry EPA Clean Diesel Fuel Implementation Workshop was held in Houston, Texas. This workshop was sponsored by a broad cross-section of trade organizations representing the diesel fuel producers and distributors who will be responsible for compliance with the 15 ppm highway diesel standard: the National Petroleum Refiners Association (NPRA), the Association of Oil Pipelines (AOPL), the Independent Fuel Terminal Operators Association (IFTOA), the National Association of Convenience Stores (NACS), the Society of Independent Gasoline Marketers of America, and the Petroleum Marketers Association of America (PMAA). The workshop featured over 20 presentations by industry the topic of distributing 15 ppm diesel fuel, as well as a questions and answers discussion.³⁴ Some of these presentations contained the results of the first test programs conducted by the pipeline industry to develop procedures and identify the changes needed to limit sulfur contamination. These initial test programs did not resolve all of industry's concerns related to the ability to limit sulfur contamination during the distribution of 15 ppm diesel fuel. However, the results were promising and indicated that with further testing and development the distribution industry can successfully manage sulfur contamination during the distribution of 15 ppm diesel fuel. We understand that the fuel distribution industry is in the process of conducting

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such additional work and that there are plans to develop standard industry practices for each segment of the distribution industry to limit sulfur contamination. We will keep abreast of developments in this area.

Due to the need to prepare for compliance with the highway diesel program, we anticipate that issues related to limiting sulfur contamination during the distribution of 15 ppm nonroad diesel fuel will be resolved well in advance of the proposed 2010 implementation date for nonroad fuel. We are not aware of any additional issues that might be raised unique to nonroad fuel. If anything we anticipate limiting contamination will become easier. We expect that 15 ppm nonroad diesel fuel will be distributed in fungible batches with 15 ppm highway diesel fuel up to the point when it leaves the terminal and nonroad diesel fuel must be dyed per IRS requirements. The resulting larger batch sizes as a percentage of the total 15 ppm diesel throughput may make it somewhat easier to limit sulfur contamination and could reduce losses to product downgrade during transportation by pipeline. We also expect that the projected disappearance of heating oil from much of the distribution system outside of the North East, adjoining parts of the Midwest, and North West would tend to lessen the opportunity for sulfur contamination.

We do not anticipate that there would be a substantial increase in the number of off-specification 15 ppm diesel fuel batches in the distribution system due to sulfur contamination. To the extent that there are off-specification batches of nonroad (and highway) diesel fuel, the 500 ppm locomotive and marine diesel fuel markets could provide a market for off-spec product that could be important to during the transition to 15 ppm nonroad diesel fuel in 2010.

5.6.4 Potential need for Additional Product Segregation Due to the Implementation of the Proposed 15 ppm Sulfur Specification for Nonroad Diesel Fuel

Two of the three factors discussed in 5.4 of this Draft RIA regarding the potential need for additional product segregation due to the implementation of the proposed 500 ppm NRLM standard in 2007 also apply with respect to the potential impact of the proposed 15 ppm standard for nonroad diesel fuel in 2010: 1) the application of a different sulfur standard to a portion of the non-highway distillate pool based on end-use, and 2) the Internal Revenue Service (IRS) requirement that diesel fuel used in non-highway engines be dyed prior to sale to consumers to indicate its non-taxed status before it leaves the terminal. The potential impact on product segregation of the proposed marker requirement was discussed in 5.4 of this Draft RIA within the context of the proposed 500 ppm sulfur specification for NRLM fuel in 2007 and for locomotive and marine diesel fuel in 2010. The implementation of the proposed 15 ppm sulfur standard would not alter the conclusions we reached in 5.4 regarding the potential impacts on the proposed marker requirements

The following discussion evaluates the potential need for additional product segregation in each segment of the distribution system from the refinery through to the end-user due to the implementation of the proposed 15 ppm sulfur standard for nonroad diesel fuel.

Refineries:

Due to economies of scale involved in desulfurization, we expect that most individual refineries would choose to manufacture a single or perhaps in some case two sulfur grades of diesel fuel. We do not anticipate that individual refineries would produce substantial quantities of all the different sulfur grades (15 ppm, 500 ppm locomotive and marine, and heating oil). We do not anticipate the need for additional product segregation at refineries. As discussed above, we do not anticipate that there would be any physical differences between 15 ppm manufactured for the highway market and 15 ppm diesel fuel manufactured for the non-highway market. Today's proposal would allow 15 ppm diesel fuels intended for the highway and nonroad markets to be shipped fungibly until NRLM fuel is dyed for IRS excise tax purposes. Therefore, today's proposed 15 ppm sulfur standards for nonroad diesel fuel would not require refiners to put in new product storage tanks.

A limited number of refiners would be allowed to produce 500 ppm nonroad diesel fuel until 2010. However, we expect that such fuel would be distributed via segregated means from the refinery to the end-user. Thus, we do not expect that such fuel would result in the need for additional tankage.

Pipelines:

Under today's proposal, pipeline operators would ship only one 15 ppm diesel fuel. Therefore, we do not expect that the proposed 15 ppm nonroad diesel sulfur standards would necessitate the need for additional product segregation in the pipeline distribution system (i.e. there would be no increase in the number of different diesel fuel grades carried by the pipeline system relative to 2007). Due to the large reduction in the potential 500 ppm diesel pool that would accompany the implementation of the proposed 15 ppm nonroad diesel sulfur standard, we expect that 500 ppm diesel fuel would all but disappear from the fungible pipeline distribution system. This could result in a simplification of in the number of fuel grades carried in certain parts of the fungible distribution system.

We also project that today's program would not result in an increase the volume of product downgrade or transmix. To the contrary, similar to the situation associated with shipping batches of 500 ppm diesel fuel by pipeline until 2010, there may be some opportunity for improved efficiency (i.e. a reduction in downgrade and transmix volumes) because of the increase in 15 ppm batch sizes shipped by pipeline.

Terminals:

Under the proposed sulfur program we expect that terminal operators would maintain storage facilities for a single 15 ppm diesel fuel. Only when 15 ppm fuel leaves the refinery would it be segregated into two distinct products due the addition of dye to nonroad diesel fuel per the IRS requirements to indicate its non-taxed status. Therefore, we do not expect that the implementation of the proposed 15 ppm nonroad sulfur standard would result in the need for additional product segregation at terminals.

Bulk Plants:

When the 15 ppm standard for nonroad diesel fuel would be implemented in 2010, we expect that bulk plant operators would switch the tank that previously contained 500 ppm NRLM to dyed 15 ppm nonroad service in 2010.³⁵ Therefore, we do not anticipate the need for additional product segregation at bulk plants due to the implementation of the proposed 15 ppm nonroad sulfur specification.

5.7 Impacts on the Engineering and Construction Industry

An important aspect of the feasibility of any fuel quality program is the ability of the refining industry to design and construct any new equipment required to meet the new fuel quality standard. In this section we assess the impact of the proposed NRLM fuel program on engineering design and construction personnel needs. Specifically, we focus on three types of workers: front-end designers, detailed designers and construction workers needed to design and build new desulfurization equipment. In doing this, we consider the impacts of the Tier 2 gasoline sulfur and the 2007 highway diesel sulfur programs on these same types of personnel standard and the proposed nonroad diesel sulfur programs. We compare the overall need for these workers to estimates of total employment in these areas. In general, it would also be useful to expand this assessment to specific types of construction workers which might be in especially high demand, such as pipe-fitters and welders. However, estimates of the number of people currently employed in these job categories are not available. Thus, it is not possible to determine how implementing the nonroad diesel fuel sulfur cap and other programs might stress the number of personnel needed in these specific job categories.

To accomplish this task, we first estimated the level of design and construction resources related to revamped and new desulfurization equipment. We next projected the number of revamped and new desulfurization units which would be needed under the proposed NRLM fuel program, as well as under a couple of alternative programs also considered. Then, we developed a schedule for how desulfurization projects due to be completed at the same time might be spread out during the year. We next developed a time schedule for when the various resources would be needed throughout each project. Finally, we project the level of design and construction resources needed in each month and year from 2003 and 2014 and compare this to the number of people employed in each job category.

5.7.1 Design and Construction Resources Related to Desulfurization Equipment

The number of job-hours necessary to design and build individual pieces of equipment and the number of pieces of equipment per project were taken from an NPRA technical paper by Moncrief and Ragsdale.³⁶ Their study was performed to support a recent National Petroleum Council study of gasoline and diesel fuel desulfurization, as well as other potential fuel quality changes.³⁷ These estimated job hours are summarized in Table 5.7-1.

Table 5.7-1
Design and Construction Factors for Desulfurization Equipment

	Gasoline ^a	Highway and Nonroad Diesel Treaters	Highway and Nonroad Diesel Treaters
	New Hydrotreater	New Hydrotreater	Revamp Existing Hydrotreater
Number of Pieces of Equipment per Refinery	60	60	30
Job hours per piece of equipment ^a			
Front End Design	300	300	150
Detailed Design	1200	1200	600
Direct and indirect construction	9150	9150	4575

^a Revamped equipment estimated to require half as many hours per piece of equipment. All gasoline treaters for Tier 2 compliance are assumed to be new.

5.7.2 Number and Timing of Revamped and New Desulfurization Units

In the Final Regulatory Impact Analysis for the 2007 highway diesel program, we estimated the number of new and revamped desulfurization units projected for both the Tier 2 and highway diesel fuel programs.³⁸ We updated the projections for the 2007 highway diesel program per the analysis presented in Section 7.2.2.1. These projections are shown in Table 5.7-2 below.

Table 5.7-2
Number of Gasoline and Highway Diesel Desulfurization Units Becoming Operational^{a39}

Fuel Type and Stage	Before 2004	2004	2005	2006	2007	2008	2009	2010
New gasoline desulfurization units	10	37	6	26	5	3	4	6
Highway Diesel Desulfurization Units (80% revamps, 20% new)				74				40

^a Units become operational on January 1st for gasoline desulfurization and June 1st for highway diesel desulfurization units.

The next step was to estimate the types of equipment modifications necessary to meet the proposed NRLM fuel requirements. This was a complex task, due to the close integration of the highway and NRLM fuel programs and the fact that refiners' relative production of highway and

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high sulfur distillate fuel varies dramatically. Therefore, we broke refiners of high sulfur distillate into three categories and assessed their need for new or revamped desulfurization equipment separately. The categories as discussed in Section 7.2.1 are: highway refiners (95% or more of their no. 2 distillate production meets highway diesel fuel specifications), high sulfur refiners (5% or less of their no. 2 distillate production meets highway diesel fuel specifications), mix refiners (producers of high sulfur distillate fuel not falling into one of the other categories).

Table 5.7-3 presents the results of our analysis of the 62 refineries which are projected to produce either 500 or 15 ppm NRLM diesel fuel under the proposed program. The methodology used to determine that these 62 refineries would produce NRLM diesel fuel is described in Section 7.2.

Table 5.7-3
Types of Equipment Modifications Needed Under the Proposed NRLM Fuel Program

Fuel Type	Year and Fuel Control	Highway Refiners	Mix 2006 Refiners ^a			Mix 2010 Refiners ^a			High Sulfur Refiners	
		Units	New Units	Revamp Units	None	New Units	Revamp Units	None	Units	Revamp
15 ppm Highway Diesel Hydrotreater Modifications	2006	8	7 (4)	12					0	
	2010	2				11 (9)	8		0	
	Total	10	19			19			14	
High Sulfur Diesel Hydrotreater Modifications	2007 500 ppm fuel (total of 42)	7	12 (1)	0	3	12 (4)	0	0	8	0
	2010 500 ppm fuel (total of 20)	3	4 (3)	0	0	0	7 (5)	0	6	0
	2010 15 ppm fuel (total of 25)	5	2	6 (1)	0	0	0	8 (2)	0	4
	2014 15 ppm fuel (total of 12)	3	0	5 (3)	0	0	4 (3)	0	0	0

^a Numbers in parentheses are a subset for each category and represent mix refineries that currently have no highway diesel fuel hydrotreater.

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As shown in the Table 5.7-3, we project that 10 highway refineries, 38 mix refineries and 14 high sulfur refineries are projected to produce NRLM diesel fuel in 2007 and beyond. Refineries in the first two categories also produce highway diesel fuel. We further sub-divide refineries in these two categories according to whether they are projected to produce 15 ppm highway diesel fuel in 2006 or 2010, because the timing of their modifications to their highway diesel fuel hydrotreater can affect what modifications are necessary to produce 500 ppm or 15 ppm NRLM diesel fuel. As shown, of the 10 highway refineries, we project that 8 will revamp or replace their current hydrotreater in 2006, while the other two will do so in 2010. Of the 38 mix refineries, we project that half will revamp or replace their current hydrotreater in 2006, while the other half will do so in 2010. No current high sulfur refineries are projected to produce 15 ppm highway diesel fuel in either 2006 or 2010. It should be noted that the 48 highway and mix refineries shown in Table 5.7-3 are not all the refineries producing highway diesel fuel today or in 2006 and beyond. The 48 refineries are those which are projected to produce some highway diesel fuel in 2006 and beyond, as well as NRLM fuel in 2007 and beyond.

Regarding the highway refineries, our cost analysis projects that 7 would produce 500 ppm NRLM fuel in 2007. Five of these refineries would further desulfurize their 500 ppm NRLM diesel fuel to 15 ppm in 2010, while three new highway refineries would produce 500 ppm NRLM diesel fuel for the first time in 2010. Finally, in 2014, an additional three refineries would further desulfurize their 500 ppm NRLM diesel fuel to 15 ppm in 2014, leaving 2 highway refineries producing 500 ppm NRLM diesel fuel in the long term.

As mentioned above, the highway refineries produce relatively small quantities of high sulfur distillate today (i.e., less than 5% of total no. 2 distillate production). Thus, we project that these refineries could incorporate their high sulfur distillate into the design and construction of their highway hydrotreaters with no additional engineering or construction requirements. Section 7.2.2 describes the type of hydrotreater modifications which are projected for highway refineries to enable the production of low sulfur NRLM diesel fuels.

Moving to the mix refineries, their treatment depends on when they are projected to produce 15 ppm highway diesel fuel and whether or not they would do so by revamping their current hydrotreater or construct the new hydrotreater. Of the 19 mix refineries which are projected to produce 15 ppm highway diesel fuel in 2006 (“2006 mix refineries”), we project that 7 would construct a new hydrotreater. We project that 4 of these 7 refineries would need a new hydrotreater because available data indicate that they do not currently have a no. 2 distillate hydrotreater. We assumed that 20% of the remaining 15 refineries (3 refineries) would need a new hydrotreater. This is consistent with the analysis and assumptions for the 2007 highway rule, where we estimated that 20% of all refineries producing highway diesel fuel would need a new hydrotreater. Discussions with industry continue to confirm the reasonableness of this assumption. (The other 80% are projected to be able to revamp their current hydrotreater to produce 15 ppm diesel fuel.) The same procedure was applied to the 19 mix refineries projected to produce 15 ppm highway diesel fuel initially in 2010 (“2010 mix refineries”). The only difference was that 9 of these refineries apparently do not currently have a no. 2 distillate hydrotreater, therefore necessitating that a new one be built.

In 2007, we project that 15 2006 mix refineries would begin producing 500 ppm NRLM diesel fuel. Twelve of these are projected to need to construct a new hydrotreater to do so, while three do not. These three refineries are those which built new hydrotreaters in 2006 to produce 15 ppm highway diesel fuel and which also currently have a highway diesel fuel hydrotreater. These three refineries could use their current highway diesel fuel hydrotreater to produce 500 ppm NRLM diesel fuel. Four additional 2006 mix refineries would begin producing 500 ppm NRLM diesel fuel in 2010, with all needing to construct new hydrotreaters to do so.

We project that 13 of the 19 2006 mix refineries would produce 15 ppm nonroad diesel fuel, beginning either in 2010 or 2014. All but two of these units would be revamps of units built in 2007. The two new 15 ppm units would be at refineries projected to produce 500 ppm NRLM diesel fuel in 2007 with the current highway diesel fuel hydrotreater.

In 2007, we project that 12 2010 mix refineries would begin producing 500 ppm NRLM diesel fuel. All of these refineries are projected to need to construct a new hydrotreater to do so, because they will need their existing hydrotreater to continue producing 500 ppm highway diesel fuel through 2009. Seven additional 2010 mix refineries would begin producing 500 ppm NRLM diesel fuel in 2010. All seven of these refineries are projected to incorporate the desulfurization of NRLM diesel fuel into their plans for producing 15 ppm highway diesel fuel in 2010. Due to the significant volume of NRLM fuel involved, we project that the resources needed to add the desulfurization of NRLM fuel to their plans would constitute a revamp of a desulfurization unit.

We project that 12 of the 19 2010 mix refineries would produce 15 ppm nonroad diesel fuel, beginning either in 2010 or 2014. The 10 refineries beginning 15 ppm nonroad fuel production in 2010 are projected to not require significant amounts of additional design and construction resources, as these units were designed in 2007 to be easily revamped in 2010 to produce 15 ppm fuel. The 4 refineries beginning 15 ppm nonroad fuel production in 2014 are projected to require a modest amount of additional design and construction resources (revamp level), as these refineries built new desulfurization capacity in 2010 to produce 500 ppm NRLM fuel at the same time that they began production of 15 ppm highway diesel fuel. Therefore, we projected that they would likely require some additional engineering and construction resources to produce 15 ppm nonroad fuel in 2014.

Moving to the high sulfur refineries, we project 8 such refineries would begin producing 500 ppm NRLM diesel fuel in 2007 and 6 more refineries in 2010. All of these refineries are projected to need to construct a new hydrotreater to produce 500 ppm NRLM fuel, because their existing hydrotreating capacity is likely only capable of producing 2000-5000 ppm sulfur levels. In 2010, we project that 4 of these refineries producing 500 ppm NRLM diesel fuel in 2007 would revamp their units to produce 15 ppm nonroad diesel fuel.

We repeated this analysis for two of the alternative NRLM fuel programs considered in developing this proposed rule: 1) the proposed program plus extension of the 15 ppm cap to locomotive and marine diesel fuel in 2010 (two step 15 ppm NRLM) and 2) a one step program

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consisting of the final standards as the proposal, but with all the standards occurring in 2008 (one step in 2008). The breakdown of desulfurization equipment modifications required under the two step 15 ppm NRLM program are summarized in Table 5.7-4. There are no differences between this program and the proposal with respect to the production of 500 ppm fuel in 2007 in 2010. However, due to the further control of locomotive and marine diesel fuel to 15 ppm in 2010, additional new and revamped units would be needed in 2010.

We again repeated this analysis for the one step NRLM fuel program in 2008. The results are shown in Table 5.7-5. The key difference here is that most new and revamped units occur in 2008. Also, we project more revamped units and fewer new units for 2010 mix refineries as we project that these refineries would combine their plans to produce 15 ppm highway and nonroad diesel fuel.

Table 5.7-6 summarizes the results of Tables 5.7-3 through 5.7-5.

Table 5.7-4
Types of Equipment Modifications Needed Under the
Two Step Alternative Program with 15 ppm NRLM Diesel Fuel in 2010

Fuel Type	Year and Fuel Control	Highway Refiners	Mix 2006 Refiners ^a			Mix 2010 Refiners ^a			High Sulfur Refiners	
		Units	New Units	Revamp Units	None	New Units	Revamp Units	None	Units	Revamp
15 ppm Highway Diesel Hydrotreater Modifications	2006	8	7 (4)	12					0	
	2010	2				11 (9)	8		0	
	Total	10	19			19			14	
High Sulfur Diesel Hydrotreater Modifications	2007 500 ppm fuel (total of 42)	7	12 (1)	0	3	12 (4)	0	0	8	0
	2010 500 ppm fuel (total of 20)	3	4 (3)	0	0	0	7 (5)	0	6	0
	2010 15 ppm fuel (total of 43)	7	2	13 (1)	0	0	0	15 (2)	0	6
	2014 15 ppm fuel (total of 12)	3	0	5 (3)	0	0	4 (3)	0	0	0

^a Numbers in parentheses are a subset for each category and represent mix refineries that currently have no highway diesel fuel hydrotreater.

Table 5.7-5
Types of Equipment Modifications Needed Under the
One Step Alternative Program with 15 ppm Nonroad and 500 ppm L&M Fuel in 2010

Fuel Type	Year and Fuel Control	Highway Refiners	Mix 2006 Refiners ^a			Mix 2010 Refiners ^a			High Sulfur Refiners	
		Units	New Units	Revamp Units	None	New Units	Revamp Units	None	Units	Revamp
15 ppm Highway Diesel Hydrotreater Modifications	2006	8	7 (4)	12					0	
	2010	3				11 (9)	10		0	
	Total	11	19			21			13	
High Sulfur Diesel Hydrotreater Modifications	2008 500 ppm fuel (total of 13)	0	4	0	1	0	5 (2)	0	3	0
	2008 15 ppm fuel (total of 30)	7	10 (1)	0	0	0	7 (2)	0	6	0
	2012 500 ppm fuel (total of 12)	2	1	0	0	0	4 (2)	0	5	0
	2012 15 ppm fuel (total of 7)	1	(3)	0	0	0	3 (3)	0	0	0

^a Numbers in parentheses are a subset for each category and represent mix refineries that currently have no highway diesel fuel hydrotreater.

Table 5.7-6
Number and Timing of NRLM Desulfurization Units

Program	Type of Treater	2007	2008	2009	2010	2011	2012	2013	2014
Proposed Two Step Program	No Treaters Modification	10			16				3
	Revamp Treaters	0			17				9
	New Treaters	32			12				0
	Total Units	42			45				12
Proposed Two Step Program with 15 ppm Locomotive and Marine Fuel in 2010	No Treaters Modification	10			25				3
	Revamp Treaters	0			26				16
	New Treaters	32			11				0
	Total Units	42			62				19
One Step NRLM Program in 2008	No Treaters Modification		7				3		
	Revamp Treaters		12				7		
	New Treaters		24				9		
	Total Units		43				19		

5.7.3 Timing of Desulfurization Projects Starting up in the Same Year

A worst case assumption would be that all of the units scheduled to start up on January 1 for gasoline and June 1 for diesel would begin and complete their design and construction at the exact same time. However, this is not reasonable for a couple of reasons. Our early credit programs for gasoline, highway and nonroad diesel production will entice some refiners to make treater modifications ahead of our program startup dates thus shifting E&C workload ahead for these refiners. Also, an industry-wide analysis such as this one assumes that all projects take the same amount of effort and time. This means that each refinery is using every specific type of resource at exactly the same time as other refineries with the same start-up date. However, refineries' projects will differ in complexity and scope. Even if they all desired to complete their project on the same date, their projects would begin over a range of months. Thus, two projects scheduled to start up at exactly the same time are not likely to proceed through each step of the design and construction process at the same time. Second, the design and construction industries will likely provide refiners with economic incentives to avoid temporary peaks in the demand for personnel. Thus, with respect to units starting up in a given year, we assumed that the design and construction of these units would be spread out throughout the year, with 25 percent of the units

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starting up per quarter. Given this assumption, we developed the breakdowns of personnel requirements by month for a given project shown in Table 5.7-7.

5.7.4 Timing of Design and Construction Resources Within a Project

The next step in this analysis was to estimate how the engineering and construction resources are spread out during a project. The results of this analysis are summarized in Table 5.7-7.

Table 5.7-7
Distribution of Personnel Requirements Throughout the Project

	<i>Front-End Design</i>	<i>Detailed Engineering</i>	<i>Construction</i>
Duration per project	6 months	11 months	14 months
Duration for projects starting up in a given calendar year	15 months	20 months	23 months
<i>Fraction of total hours expended per month from start of that portion of the project</i>			
1	0.050	0.020	0.030
2	0.050	0.030	0.030
3	0.050	0.040	0.030
4	0.078	0.040	0.040
5	0.078	0.040	0.040
6	0.078	0.050	0.040
7	0.078	0.050	0.040
8	0.078	0.060	0.050
9	0.078	0.065	0.050
10	0.078	0.075	0.055
11	0.078	0.075	0.055
12	0.078	0.075	0.060
13	0.050	0.060	0.060
14	0.050	0.060	0.055
15	0.050	0.050	0.055
16		0.050	0.050
17		0.040	0.050
18		0.040	0.040
19		0.030	0.040
20		0.020	0.040
21			0.030
22			0.030
23			0.030

The figures shown in Table 5.7-7 were taken from a similar analysis performed in support of the 2007 highway diesel fuel program. The fraction of total hours expended each month

estimated in Table 5.7-7 was derived based on the following. Per Moncrief and Ragsdale, front end design typically takes six months to complete.⁴⁰ If 25 percent of the refineries scheduled to start of in a given year start their projects every quarter, each subsequent group of the refineries starts when the previous group is halfway through their front end design. Overall, front end design for the four groups covers a period of 15 months, or 6 months for the first group plus 3 months for each of the three subsequent groups. In spreading this work out over the 15 months, we assumed that the total engineering effort would be roughly equal over the middle 9 months. The effort during the first and last 3 month period would be roughly two-thirds of that during the peak middle months. The same process was applied to the other two job categories. Finally, we assumed that personnel were able to actively work 1877 hours per year, or at 90 percent of capacity assuming a 40 hour work week. The reader is referred to the Final RIA for the 2007 highway diesel rule for a more detailed description of the methodology used.

5.7.5 Projected Levels of Design and Construction Resources

Applying the above factors, we projected the maximum number of personnel needed in any given month for each type of job for the desulfurization projects related to the Tier 2 gasoline, highway diesel fuel and NRLM diesel fuel programs combined. The results are shown in Table 5.7-8. In addition to total personnel required, the percentage of the U.S. workforce currently employed in these areas is also shown. These percentages were based on estimates of recent employment levels for the three job categories: 1920 front end design personnel, 9585 detailed engineering personnel and roughly 160,000 construction workers (taken from Moncrief and Ragsdale).

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Table 5.7-8
Maximum Monthly Demand for Personnel

	<i>Front-End Design</i>	<i>Detailed Engineering</i>	<i>Construction</i>
Tier 2 Gasoline Sulfur Program Plus Highway Diesel Fuel Program			
Number of Workers	630 (Apr 03)	2,223 (Apr 04)	14,614 (Nov 04)
Current Workforce ^a	33%	23%	9%
With Proposed Two Step NRLM Program			
Number of Workers	630 (Apr 03)	2,223 (Apr 04)	17,176 (Dec 04)
Current Workforce ^a	33%	23%	11%
With Proposed Two Step NRLM Program with 15 ppm NRLM in 2010			
Number of Workers	630 (Apr 03)	2,223 (Apr 04)	17,076 (Dec 04)
Current Workforce ^a	33%	23%	11%
With One Step NRLM Program in 2008			
Number of Workers	630 (Apr 03)	2,223 (Apr 04)	14,614 (Dec 04)
Current Workforce ^a	33%	23%	9%

^a Based on recent employment in the U.S. Gulf Coast, assuming that half of all projects occur in the Gulf Coast. The year and month of maximum personnel demand is shown in parenthesis.

As can be seen from Table 5.7-8, the proposed NRLM diesel fuel program does not impact the maximum monthly personnel requirements for either front end design or detailed engineering design. Maximum use of construction personnel is increased slightly, by 2% in November of 2004. This appears to be a minor impact. The primary reason for the lack of impact is that the 2007 implementation date for the 500 ppm NRLM standard is later than the primary 2004-2006 phase-in period for the Tier 2 gasoline program and the 2006 implementation date for the 15 ppm highway diesel fuel standard.

The alternative two step NRLM program with a 15 ppm cap on locomotive and marine diesel fuel would have the same impact, since the difference between this alternative and the proposal occurs in 2010, after the peak impacts occurs. The alternative one step NRLM fuel program in 2008 avoids any impact on the peak resource need due to its starting one year later.

Tables 5.7-9, 5.7-10 and 5.7-11 present a summary of the average personnel demand for the three job categories in each year.

Table 5.7-9.
Annual Front End Engineering Personnel Demand

<i>Calendar Year</i>	<i>Gasoline + Highway Diesel Baseline</i>	<i>Plus Two Step Nonroad to 15 ppm in 2010</i>	<i>Plus Two Step to 15 ppm in 2010</i>	<i>Plus One Step to 15 ppm in 2008</i>
2003	534	549	549	534
2004	83	344	344	100
2005	32	64	64	325
2006	57	67	67	9
2007	231	398	444	231
2008	23	42	48	29
2009	0	0	0	102
2010	0	2	4	18
2011	0	37	65	0
2012	0	4	8	0
2013	0	0	0	0
2014	0	0	0	0

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Table 5.7-10
Annual Detailed Engineering Personnel Demand

<i>Calendar Year</i>	<i>Gasoline + Highway Diesel Baseline</i>	<i>Plus Two Step Nonroad to 15 ppm in 2010</i>	<i>Plus Two Step to 15 ppm in 2010</i>	<i>Plus One Step to 15 ppm in 2008</i>
2003	1166	1166	1166	1166
2004	1656	1988	1988	1656
2005	372	1207	1207	682
2006	345	407	407	1128
2007	593	806	842	651
2008	757	1292	1383	757
2009	46	84	92	175
2010	0	0	0	326
2011	0	46	83	24
2012	0	117	209	0
2013	0	9	15	0
2014	0	0	0	0

Table 5.7-11
Construction Worker Personnel Demand

<i>Calendar Year</i>	<i>Gasoline + Highway Diesel Baseline</i>	<i>Plus Two Step Nonroad to 15 ppm in 2010</i>	<i>Plus Two Step to 15 ppm in 2010</i>	<i>Plus One Step to 15 ppm in 2008</i>
2003	4,914	4,914	4,914	4,914
2004	12,462	12,743	12,742	12,462
2005	7,653	12,800	12,800	7,916
2006	249	4,179	4,179	5,074
2007	579	759	790	4,264
2008	4,948	8,246	8,810	4,948
2009	3,246	5,764	6,194	3,356
2010	0	0	0	2,010
2011	0	40	70	1,535
2012	0	724	1,287	0
2013	0	553	983	0
2014	0	0	0	0

The impact of the nonroad programs on the maximum monthly demand for front end design is not increased from the 2000 highway rule determinations. Thus, 33 percent of available front end personnel U.S. resources are required for the nonroad programs which is not different than the maximum predicted impact for the highway diesel rule. The annual front end demand for personnel in Table 5.7-9 reveals that the front end resource demands are spaced over many years with an initial peak in years 2003-04 and a second sub peak in 2006-07. The level of front end resource demand drops off dramatically after years 2003 and 2004. Detailed engineering annual demands for nonroad has a maximum peak in years 2003-05 and a second sub peak in years 2006-08. Neither of the peaks represent a significant percentage of available detailed resources and furthermore are not higher than demands determined for the highway diesel program. The nonroad programs contribute to the second peak in front end engineering and detailed engineering in demands in 2006-07, but we believe the yearly time spread in peak resource demand will provide an ample period for E&C industry to respond to nonroad implementation. The maximum monthly impact on construction services is not significant at eleven percent of available industry which is not considerably increased over highway diesel requirements, see Table 5.7-11. Thus, we believe the construction industry should be able to provide services for the nonroad programs.

Thus, we believe that the E&C industry is capable of supplying the refining industry with the equipment necessary to comply with our proposed nonroad diesel fuel programs. We believe

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that this is facilitated by the synergies obtained with highway diesel rule implementation and the later phase in dates for nonroad compliance.

5.8 Supply of Nonroad, Locomotive, and Marine Diesel Fuel (NRLM)

EPA has developed the proposed fuel program to minimize its impact on the supply of distillate fuel. For example: we have proposed to transition the fuel sulfur level down to 15 ppm in two steps, providing an estimated 6 years of leadtime for the final step; up to 10 years for small refiners. We are proposing to provide flexibility to refiners through the availability of banking and trading provisions and we are proposing hardship provisions for qualifying refiners. In order to evaluate the effect of this proposal on supply, EPA evaluated four possible cases: 1) whether today's proposed standards could cause refiners to remove certain blendstocks from the fuel pool, 2) whether the proposed standards could require chemical processing which loses fuel in the process, 3) whether the cost of meeting the proposed standards could lead some refiners to leave that market, and 4) whether the cost of meeting the proposed standards could lead some refiners to stop operations altogether (i.e., shut down). In all cases, as discussed below, we have concluded that the answer is no. Therefore, consistent with our findings made during the 2007 highway diesel rule, we do not expect this proposed rule to cause any supply shortages of nonroad, locomotive and marine diesel fuel.

Blendstock Shift: As mentioned above, we first evaluated whether certain blendstocks or portions of blendstocks may need to be removed from the NRLM diesel fuel pool. Technology exists to desulfurize any commercial diesel fuel to less than 10 ppm sulfur. Technologies, such as hydro-dearomatization, have been used on a commercial scale. More direct, desulfurization technologies are just being demonstrated as refiners in both the U.S. and Europe are producing selected batches of number 2 diesel fuel at 15 ppm sulfur or less. Pilot plant studies have demonstrated that diesel fuels consisting of a wide range of feedstocks and containing high levels of sulfur can be desulfurized to less than 15 ppm. Such studies and experience have reliably demonstrated that at pressures within the range of many current conventional hydrotreaters, the single most important variable that limits desulfurization to very low sulfur levels is the length of time the fuel is in contact with hydrogen and the catalyst. This "residence time" is primarily a function of reactor volume. Therefore, we believe there is no technical reason to remove certain feedstocks from the diesel fuel pool. It may cost more for refiners to process certain blendstocks, such as light cycle oil, than others. Consequently, there may be economic incentives for refiners to move these blendstocks out of the diesel fuel market to reduce compliance costs. However, that is an economic issue, not a technical issue and will be addressed below. Thus, this rulemaking should not result in any long term reduction in the volume of products derived from crude oil available for blending into diesel fuel or heating oil.

As mentioned above, certain feedstocks are more expensive to desulfurize than others. The primary challenge of desulfurizing distillate to sulfur levels meeting the 15 ppm cap is the presence of sterically hindered compounds, particularly those with two methyl or ethyl groups

blocking the sulfur atom¹. These compounds are aromatic in nature, and are found in greatest concentration in light cycle oil (LCO), which itself is highly aromatic. These compounds can be desulfurized readily if saturated. However, due to the much higher hydrogen cost of doing so, it is better economically if this can be avoided. Because these compounds are large in size and high in molecular weight due to their chemical structure, they distill near the high end of the diesel range of distillation temperatures. Thus, it is technically possible to segregate these compounds from the rest of the cracked stocks via distillation and avoid the need to desulfurize them. However, this would likely require the construction of a distillation column and significant operating costs in the form of heat input. Another option would be to use the existing FCC fractionator to shift these heavy molecules out of the LCO pool. They would be shifted to slurry oil, which eventually becomes part of residual fuel. Once there, it would be very difficult to recover them for blending into heating oil. Residual fuel is priced well below diesel fuel. The residual fuel oil market is also not growing. Thus, shifting heavy LCO to residual fuel would involve a significant long term reduction in revenue (and profits). Thus, we do not believe that many refiners would attempt to reduce the cost of desulfurizing diesel fuel in this way.

It is more feasible to shift some or all of the LCO stream to the heating oil pool. It is unlikely to be shifted to locomotive and marine (LM) diesel fuel due to their 40 minimum cetane specification and the very low cetane level of LCO. Straight run distillate could be shifted from heating oil to diesel fuel to compensate for the volume. Thus, little if any volume loss of NRLM diesel fuel should result. However, even this approach would require the refiner to maintain separate inventories of NRLM diesel fuel and heating oil, which may require additional tankage. Of course, the refiner would need to have access to a significant heating oil market after 2007.

In our cost projections, we projected that individual refineries would produce either 15 ppm, 500 ppm or high sulfur distillate to avoid additional tankage and maximize economies of scale for the desulfurization equipment. Thus, we did not assume that refiners could reduce costs by shifting feedstocks around, such as sending LCO to heating oil and straight run from heating oil to NRLM diesel fuel. Despite this, the costs appear to be reasonable. Thus, some refiners with adequate tankage and access to the heating oil market may be able to reduce costs with such an exchange of feedstocks. However, we did not factor these savings into our cost projections. Nor should such exchanges reduce the supply of NRLM diesel fuel.

Processing Losses: We evaluated whether the proposed standards could require chemical processing which results in fuel losses. Conventional desulfurization processes do not reduce the energy content of feedstocks, although the feedstock composition may be slightly altered. A conventional hydrotreater which is used to produce 15 ppm sulfur diesel converts about 98 percent of its feedstock to finished diesel fuel. About 1.5 percent of the remaining two-percent leaves the unit as naphtha or light-crackate (i.e., gasoline feedstock), while the last 0.5 percent is split about evenly between liquified petroleum gas (LPG) and refinery fuel gas. Both naphtha and LPG are valuable liquids which are used to produce other finished products including

¹Meeting a 500 ppm cap standard can be met without desulfurizing much or any of the sterically hindered compounds.

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gasoline. Refiners can easily adjust the relative amounts of gasoline and diesel fuel produced by a unit, especially at the process level under discussion. This additional naphtha can displace other gasoline or kerosene blendstocks, which can then be shifted to the diesel fuel pool. LPG, on the other hand, is used primarily for space-heating, but depending on where it's produced and how it's cut, can be used as a feedstock in the petrochemical industry. Because LPG can be used for space heating, it would likely displace some volume of heating oil, which in turn could be shifted to the diesel pool. Currently, heating oil or high sulfur fuel, has the same basic composition as highway diesel, other than its sulfur content, and can be used to fuel nonroad, locomotive, and commercial marine equipment. Thus, the desulfurization process usually has little or no direct impact on a refinery's net fuel production. The volume-shift from diesel fuel to fuel gas is very small (0.25 percent) and the gas can be used to reduce consumption of natural gas within the refinery. This discussion applies to the full effect of the proposed standards (i.e., the reduction in sulfur content from 3400 ppm to 500 ppm and from 500 ppm to 15 ppm). For the first step of the proposed fuel program and that portion of the diesel fuel pool which would remain at the 500 ppm level indefinitely, the impacts would only be about 40 percent of those described above.

The conversion rate of a given feedstock to light products is reportedly much lower for the emerging or advanced technologies than for conventional hydrotreaters. For the purposes of this rulemaking, the newer or advanced technologies are only projected to be used as a second step to reduce the fuel to 15 ppm sulfur after it has been reduced from 3400 ppm to 500 ppm using conventional hydrotreating technology. We project that the Linde process might reduce the conversion to light products for the second step by 55 percent, while the Phillips SZorb® process reportedly would not convert any diesel to light products.

Exit the NRLM Diesel Fuel Market: We evaluated whether the compliance costs associated with this rulemaking could cause some refiners to consider reducing their production of NRLM or to leave those markets altogether. As mentioned above, diesel fuel and heating oil are chemically and physically similar, except for sulfur level. Thus, beginning in mid-2007, a refiner could shift his high sulfur distillate from NRLM fuel to the heating oil market and avoid the need to invest in new desulfurization equipment. Likewise, beginning in mid-2010, a refiner could either focus entirely on the 500 ppm LM markets or shift part or all of its supply to heating oil. The result would be a potential oversupply of heating oil beginning in 2007 and LM fuel and heating oil beginning in 2010. We expect such an oversupply of these fuels would result in a substantial drop in their market price and would consequently increase the cost for a given refiner to exit the NRLM diesel fuel markets. Furthermore, refiners could be forced to find new export markets for their excess high sulfur fuel. Overseas market prices are often no higher and are occasionally lower than those in the U.S. We believe that these low market differentials combined with the additional transportation costs would encourage most refiners to comply with the NRLM program to remain in the domestic low sulfur fuel markets.

We addressed this same issue during the development of the highway diesel rule (66 FR 5002). We contracted with Southwest Research Institute (SwRI) and with Muse, Stancil & Company, an engineering firm involved primarily in economic studies and evaluations

concerning the refining industry to help us assess the potential for refiners to sell their highway diesel fuel (< 500 ppm) or the blendstocks used to produce it into alternative markets. At that time, Muse, Stancil & Company found that most refiners had few domestic alternatives for accommodating highway diesel fuel or its blendstocks. PADD I imports significant quantities of high sulfur fuel for use as nonroad diesel fuel and heating oil. Muse, Stancil & Company concluded that PADD I refineries could produce less highway fuel and more high sulfur fuel and still avoid over supplying the market by reducing imports. However, refineries in other PADDs which import little, if any, high sulfur fuel would be forced to find other, less valuable markets, including new markets for export, if they exited the highway diesel fuel market. We concluded that, at current production levels, refiners faced greater economic losses trying to avoid meeting the 15 ppm cap than by trying to comply with it, even if the market did not allow them to recover their capital investment.

There are six reasons why we believe a similar conclusion can be drawn from an analysis of today's proposed rule:

1. Approximately one-half of what is currently the U.S. high-sulfur diesel fuel market will have become part of the 500 ppm and 15 ppm markets by the time the 2007 highway diesel rule and the proposed sulfur caps on NRLM fuel have been implemented. Within that same timeframe, we expect few, if any, of the common carrier pipelines, except perhaps those serving the Northeast, will carry high sulfur heating oil. Therefore, the sale of high sulfur distillate may be limited to markets that a refiner can serve by truck.
2. The technology to desulfurize fuel, including refractory feedstocks, to less than 500 ppm sulfur has been used commercially for over a decade. The technology to reduce fuel to less than 15 ppm sulfur will have been commercially demonstrated in mid-2006, a full four years prior to the implementation of the 15 ppm sulfur standard for nonroad diesel fuel.
3. The volume of fuel affected by the 15 ppm nonroad diesel fuel standard in 2010 would be only one-seventh of that affected by the 2007 highway diesel program. This dramatically reduces the required capital investment.
4. Both Europe and Japan are implementing rules to reduce sulfur levels in highway and nonroad diesel fuel to the 10-15 ppm range, which will effectively eliminate these regions as alternative export markets for high sulfur fuel.
5. Refineries outside of the U.S. and Europe are operating at a lower percentage of their capacity than U.S. refineries.^K Capacity utilization rates at U.S. refineries are well over 90 percent. Historically, if refinery utilization rates approached their maxima, it was

^K Europe currently imports diesel fuel and is expected to continue to do so. However, European sulfur caps will be equivalent to those in the U.S. Therefore, exporting distillate fuel to Europe is not an option for U.S. refiners to avoid complying with stringent sulfur caps here. Likewise, imports from European refiners are not likely.

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usually a strong indication that demand for finished products was high. In this environment, product prices usually rose and held until the demand pressure was reduced or eliminated. Foreign refinery utilization rates as well as wholesale prices tend to be well below domestic rates, again, a reflection of lower demand relative to the potential output of finished products. The preceding condition can have at least two effects on the marketing decisions domestic refiners may face. First, if foreign margins are low and U.S. market prices high, a foreign refiner could, and most likely would, sell his products into the U.S. market, thereby reducing the upward pressure on prices and likely reducing domestic refinery margins. And, second, it is highly unlikely that a domestic refiner would decide to further reduce his margins by adding the cost to ship his product into a foreign market with a less stringent sulfur standard where wholesale prices are already lower than in the U.S. Consequently, we do not believe U.S. refiners will have a reasonable opportunity to export their high sulfur fuel.

6. One measure of the overall fiscal well-being of a refining operation is its margin. Refinery profit margins^L during the 1990s were not very encouraging until about 1997. In fact, in 1994, the net margin was less than \$0.50 per refined barrel. By 1997 it had nearly tripled and by 2000 had increased to nearly five times the 1994 average. Margins leveled out again during 2001 and decreased somewhat during 2002, but recovered during the last few months of 2002 and in early 2003. Current industry projections into the future indicate the expectation for continued high profit margins.

Once refiners have made their investments to meet the proposed NRLM diesel fuel standards, or have decided to produce high sulfur heating oil, we expect that the various distillate markets would operate very similar to today's markets. When fully implemented in 2014, there will be three distillate fuels in the market, 15 ppm highway and nonroad diesel fuel, 500 ppm locomotive and marine diesel fuel and high sulfur heating oil. The market for 500 ppm locomotive and marine diesel fuel is much smaller than the other two, particularly considering that it is nationwide and the heating oil market is geographically concentrated. Therefore, the vast majority of refiners are expected to focus on producing either 15 ppm or high sulfur distillate, which is similar to today, where there are two fuels, 500 ppm and high sulfur distillate. In this case, refiners with the capability of producing 15 ppm diesel fuel have the most flexibility, since they can sell their fuel to any of the three markets. Refiners with only 500 ppm desulfurization capability can supply two markets. Those refiners only capable of producing high sulfur distillate would not be able to participate either the 15 or 500 ppm markets. However, this is not different from today. Generally, we do not expect one market to provide vastly different profit margins than the others, as high profit margins in one market will attract refiners from another via investment in desulfurization equipment.

^LThe terms "margin" or the plural "margins" are often used in the petroleum industry in reference to several different variables including "spread" or "spreads," "net margin" or "cash margin," "gross margin," and "profit margin." The numbers these terms represent are all basically a measure of a revenue minus the cost to produce that revenue, expressed on a per barrel basis of either crude oil or finished product(s).

Refinery Closure: There are a number of reasons why we do not believe that refineries would completely close down under this proposed rule. One reason is that we have included a provisions in the proposed regulations for adjustments to the sulfur caps for small refiners, as well as any refiner facing unusual financial hardship. Another reason is that nonroad, locomotive and marine diesel fuel is usually the third or fourth most important product produced by the refinery from a financial perspective. A total shutdown would mean losing all the revenue and profit from these other products. Gasoline is usually the most important product, followed by highway diesel fuel and jet fuel. A few refineries do not produce either gasoline or highway diesel fuel, so jet fuel and high sulfur diesel fuel and heating oil are their most important products. The few refiners in this category likely face the biggest financial challenge in meeting today's proposed requirements. However, those refiners would also presumably be in the best position to apply for special hardship provisions, presuming that they do not have readily available source of investment capital. The additional time afforded by these provisions should allow the refiner to generate sufficient cash flow to invest in the required desulfurization equipment. Investment here could also provide them the opportunity to expand into more profitable (e.g., highway diesel) markets.

A quantitative evaluation of whether the cost of the proposed fuel program could cause some refineries to cease operations completely would be very difficult, if not impossible to perform. A major factor in any decision to shut down is the refiner's current financial situation. It is very difficult to assess an individual refinery's current financial situation. This includes a refiner's debt, as well as its profitability in producing fuels other than those affected by a particular regulation. It can also include the profitability of other operations and businesses owned by the refiner.

Such an intensive analysis can be done to some degree in the context of an application for special hardship provisions, as discussed above. However, in this case, EPA can request detailed financial documents not normally available. Prior to such application, as is the case now, this financial information is usually confidential. Even when it is published, the data usually apply to more than just the operation of a single refinery.

Another factor is the need for capital investments other than for this proposed rule. EPA can roughly project the capital needed to meet other new fuel quality specifications, such as the Tier 2 or highway diesel sulfur standards. However, we cannot predict investments to meet local environmental and safety regulations, nor other investments needed to compete economically with other refiners.

Finally, any decision to close in the future must be based on some assumption of future fuel prices. Fuel prices are very difficult to project in absolute terms. The response of prices to changes in fuel quality specifications, such as sulfur content, as is discussed in the next section, are also very difficult to predict. Thus, even if we had complete knowledge of a refiner's financial status and its need for future investments, the decision to stay in business or close would still depend on future earnings, which are highly dependent on prices.

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Some studies in this area point to fuel pricing over the past 15 years or so and conclude that prices will only increase to reflect increased operating costs and will not reflect the cost of capital. In fact, the rate of return on refining assets has been poor over the past 15 years and until recently, there has been a steady decline in the number of refineries operating in the U.S. However, this may have been due to a couple of circumstances specific to that time period. One, refinery capacity utilization was less than 80 percent in 1985. Two, at least regarding gasoline, the oxygen mandate for reformulated gasoline caused an increase in gasoline supply despite low refinery utilization rates. While this led to healthy financial returns for oxygenate production, it did not help refining profit margins.

Today, refinery capacity utilization in the U.S. is generally considered to be at its maximum sustainable rate. There are no regulatory mandates on the horizon which will increase production capacity significantly, even if ethanol use in gasoline increases substantially.^M Consistent with this, refining margins have been much better over the past two and a half years than during the previous 15 years and the refining industry itself is projecting good returns for the foreseeable future.

Conclusions: Therefore, consistent with our findings made during the 2007 highway diesel rule, we do not expect this proposed rule to cause any supply shortages of nonroad, locomotive and marine diesel fuel.

5.9 Desulfurization Effect on Other Non-Highway Diesel Fuel Properties

5.9.1 Fuel Lubricity

Engine manufacturers depend on diesel fuel lubricity properties to lubricate and protect moving parts within fuel pumps and injection systems for reliable performance. Unit injector systems and in-line pumps, commonly used in diesel engines, are actuated by cams lubricated with crankcase oil, and have minimal sensitivity to fuel lubricity. However, rotary and distributor type pumps, commonly used in light and medium-duty diesel engines, are completely fuel lubricated, resulting in high sensitivity to fuel lubricity. The types of fuel pumps and injection systems used in nonroad diesel engines are the same as those used in highway diesel vehicles. Consequently, nonroad and highway diesel engines share the same need for adequate fuel lubricity to maintain fuel pump and injection system durability.

The state of California currently requires the use of the same diesel fuel in nonroad equipment as in highway equipment. Outside of California, highway diesel fuel is often used in nonroad equipment when logistical constraints or market influences in the fuel distribution system limit the availability of high sulfur fuel. Thus, nonroad equipment has been using federal 500 ppm sulfur diesel fuel and California diesel fuel, some of which may have been treated with

^M Both houses of the U.S. Congress are considering bills which would require the increased use of renewables, like ethanol, in gasoline and diesel fuel. While the amount of renewables could be considerable, it is well below the annual growth in transportation fuel use.

lubricity additives for nearly a decade. During this time, there has been no indication that the level of diesel lubricity needed for fuel used in nonroad engines differs substantially from the level needed for fuel used in highway diesel engines.

Diesel fuel lubricity concerns were first highlighted during the implementation of the federal 500 ppm sulfur highway diesel program and the state of California's diesel program circa 1993.⁴¹ The diesel fuel requirements in the state of California differ from the federal requirements by substantially restricting the aromatics content of diesel fuel in addition to the sulfur content. Considerable research remains to be performed to better understand which fuel components are most responsible for fuel lubricity. Nevertheless, there is evidence that the typical process used to reduce diesel fuel sulfur content or aromatics content of diesel fuel, i.e. hydrotreating, can reduce fuel lubricity. Consequently, the implementation of the proposed sulfur standards would likely require that some action be taken to maintain the lubricity of non-highway diesel fuel.

The potential impacts on fuel lubricity from adoption of NRLM sulfur standards that we are proposing are associated solely with the additional refinery processing that would be necessary to meet these standards. Although we are proposing to extend the cetane index/aromatics content specification to NRLM diesel fuel, we do not expect that this would have a significant impact on fuel lubricity. EPA requires that highway diesel fuel meet a minimum cetane index level of 40 or, as an alternative contain no more than 35 volume percent aromatics. ASTM already applies a cetane number specification of 40 to NRLM diesel fuel, which in general is more stringent than the similar 40 cetane index specification. Because of this, the vast majority of current NRLM diesel fuel already meets the EPA cetane index/aromatics specification for highway diesel fuel. Thus, the proposed requirement would have an actual impact only on a limited number of refiners and there would be little overall impact on other diesel fuel qualities (including fuel lubricity) associated with producing fuel to meet the proposed cetane/aromatic requirement.

Blending small amounts of lubricity-enhancing additives increases the lubricity of poor-lubricity fuels to acceptable levels. These additives are available in today's market, are effective, and are in widespread use around the world. Several commenters on our final rule setting a 15ppm sulfur standard for highway diesel fuel indicated that biodiesel can be used to increase the lubricity of conventional diesel fuel to acceptable levels. Some testing suggested that only two volume percent would be necessary. However, more testing may be required to determine the necessary level of biodiesel for fuels not yet being produced, such as the 15ppm fuel being proposed today.

In the United States, there is no government or industry standard for diesel fuel lubricity. Therefore, specifications for lubricity are determined by the market. Since the beginning of the 500 ppm sulfur highway diesel program in 1993, fuel system producers, engine and engine manufacturers, and the military have been working with the American Society for Testing and Materials (ASTM) to develop protocols and standards for diesel fuel lubricity in its D-975 specifications for diesel fuel. ASTM is working towards a single lubricity specification that would be applicable to all diesel fuel used in any type of engine. Although ASTM has not yet adopted specific protocols and standards, refiners that supply the US market have been treating

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diesel fuel with lubricity additives on a batch to batch basis, when poor lubricity fuel is expected. Other evidence of how refiners are ensuring adequate fuel lubricity can be found in Sweden, Canada, and the U.S. military. The U.S. military has found that traditional corrosion inhibitor additives have been highly effective in reducing fuel system component wear. Since 1991, the use of lubricity additives in Sweden's 10 ppm sulfur Class I fuel and 50 ppm sulfur Class II fuel has resulted in acceptable equipment durability.⁴² Since 1997, Canada has required that its 500 ppm sulfur diesel fuel not meeting a minimum lubricity be treated with lubricity additives.

The potential need for lubricity additives in diesel fuel meeting a 15 ppm sulfur specification was evaluated during the development of EPA's highway diesel rule. The final highway diesel rule did not establish a lubricity standard for highway diesel fuel. We believe the issues related to the need for diesel lubricity in fuel used in non-highway diesel engines are not substantially different from the those related to the need for diesel lubricity for highway engines. Consequently, we are relying on the same industry-based voluntary approach to ensuring adequate lubricity in non-highway diesel fuels that we relied upon for highway diesel fuel. Consistent with the highway diesel final rule, we believe the best approach is to allow the industry and the market to address the lubricity issue in the most economical manner. We expect that a voluntary approach would provide adequate customer protection from engine failures due to low lubricity, while providing the maximum flexibility for the industry. We expect that the American Society for Testing and Materials (ASTM) will finalize a fuel lubricity standard for use by industry that could be applied to low sulfur NRLM diesel fuel.

The degree to which removing the sulfur content from diesel fuel may impact fuel lubricity depends on the characteristics of the blendstocks used as well as the severity of the treatment process. Based on our comparison of the blendstocks and processes used to manufacture non-highway diesel engine fuels, we project that the potential decrease in the lubricity of non-highway diesel fuel that might result from the adoption of the proposed sulfur standards would be substantially the same as that experienced in desulfurizing highway diesel fuel to meet the same sulfur standard.

A refiner of diesel fuel for use in California and for much of the rest of the United States as well evaluated the impacts on fuel lubricity of the current federal and California diesel fuel requirements.⁴³ This refiner concluded that, reducing the aromatics content of diesel fuel requires more severe hydrotreating than reducing the sulfur content to meet a 500 ppm standard. Consequently, concerns regarding diesel fuel lubricity have primarily been associated with California diesel fuel and some California refiners treat their diesel fuel with a lubricity additive as needed. The subject refiner stated that outside of California, hydrotreating to meet the current 500 ppm sulfur specification seldom results in a sufficient reduction in fuel lubricity to require the use of a lubricity additive. We expect that the same hydrotreating process used to produce highway diesel fuel today would be used to reduce the sulfur content of non-highway diesel engine fuel to meet the 500 ppm sulfur standard during the first step of the proposed program. Therefore, we estimate that there would only a marginal increase in the use of lubricity additives in NRLM diesel fuel meeting the proposed 500 ppm sulfur standard for 2007.

The highway diesel program projected that hydrotreating would be the process most frequently used to meet the 15 ppm sulfur standard for highway diesel fuel in 2006. However, we project that the 2010 implementation date for the proposed 15 ppm standard for nonroad diesel fuel would allow the use of advanced technologies to remove sulfur from 80 percent of the affected nonroad diesel pool. The use of such developing desulfurization processes is discussed in 5.5 of this Draft RIA. These new processes have less of a tendency to affect other fuel properties than does hydrotreating. Therefore, the use of such new desulfurization technologies might tend to have less of an impact on fuel lubricity. However, we have no specific information with which to quantify the impacts of the developing technologies on fuel lubricity. To provide a conservatively high estimate of the potential impact of meeting the proposed 15 ppm standard for nonroad diesel fuel, we assumed that the potential impact on fuel lubricity of the new desulfurization processes would be the same as that experienced when hydrotreating diesel fuel to meet a 15 ppm sulfur standard. We therefore assumed, as we did for 15 ppm highway diesel fuel, that all 15 ppm NRLM diesel fuel would have to be treated with lubricity additives. The cost associated with the increased use of lubricity additives in 500 ppm NRLM diesel fuel in 2007 and in 15 ppm nonroad diesel fuel in 2010 is discussed in chapter 7 of this Draft RIA.

5.9.2 Volumetric Energy Content

Some of the desulfurization processes that we project would be used to meet the proposed non-highway diesel sulfur standards tend to reduce the volumetric energy content (VEC) of the fuel during processing. Desulfurization also tends to result in a swell in the total volume of fuel. These two effects tend to cancel each other out so that there is no overall loss in the energy content in a given batch of fuel that is subjected to desulfurization. Thus, we do not expect that the potential reduction in VEC which might result from the proposed sulfur standards would affect the ability of refiners to supply sufficient quantities of non-highway diesel fuel. The potential impacts on diesel supply are discussed in 5.8 of this Draft RIA.

However, since a greater volume of fuel must be consumed in the engine to produce the same amount of power, a larger volume of fuel would need to be distributed to meet the same level of demand. The potential increase in the distribution costs associated with a reduction in non-highway diesel VEC is discussed in 7.3.

The impact of desulfurization on diesel fuel VEC varies depending on the type of blendstocks and desulfurization process used. A comparison of the blendstocks used to produce non-highway diesel fuel with those used to produce highway diesel fuel is contained in 5.2 of this Draft RIA. Based on this comparison, we believe a comparable level of severity in the desulfurization process would be required to produce non-highway diesel fuel meeting a given sulfur specification as would be required to produce highway diesel fuel meeting the same sulfur specification. Refiners with experience in the use of hydrodesulfurization to manufacture both 500 ppm and 15 ppm highway diesel fuel provided us with confidential information that we used to estimate the accompanying reduction in VEC. Using this information, we estimated that hydrodesulfurization of non-highway diesel fuel to meet a 500 ppm sulfur standard would result in a reduction in volumetric energy content of 0.7 percent.

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The proposed 15 ppm sulfur standard for nonroad diesel fuel would not be implemented until 2010. The additional lead-time would allow a number of refiners to take advantage of several less-expensive desulfurization technologies currently under development to meet the proposed 15 ppm nonroad diesel sulfur standard in addition to hydrodesulfurization (see section 5.3). The new desulfurization technologies also have less of an impact on diesel fuel volumetric energy content than does hydrodesulfurization. Using the mix of desulfurization technologies we project would be available, we estimate that desulfurizing nonroad diesel fuel from 500 ppm to 15 ppm in 2010 as proposed would reduce the volumetric energy content by an additional 0.35 percent. Thus, reducing the sulfur content of nonroad diesel fuel from the current maximum 5,000 ppm sulfur cap to the proposed 15 ppm cap on sulfur content is estimated to result in a 1.1 percent reduction in VEC. The following table (5.9-1) provides a summary of the projections we used to estimate the impact of the proposed sulfur standards on VEC, including : 1) the percentage of the applicable non-highway diesel fuel pool that we expect would be desulfurized using each of the available desulfurization processes, and 2) the projected impact of each desulfurization process on VEC.

Table 5.9-1
Projections Used in Estimating the in Reduction in
Volumetric Energy Content Associated with Meeting the Proposed Sulfur Standards

Desulfurization Process ^a	Percent of Diesel Pool Desulfurized Using a Given Process to Meet the Applicable Sulfur Standard		Reduction in Volumetric Energy Content Associated with a Given Desulfurization Process	
	NR, L, & M ^b 500 ppm in 2007	NR 15 ppm in 2010	Reduction in Sulfur Content	
			HS ^c to 500 ppm	500 ppm to 15 ppm
Hydrodesulfurization	100 %	20 %	0.7%	0.7 %
S-Zorb Sulfur Adsorption	NA	40 %	NA	0.1 %
Linde Isotherming	NA	40 %	NA	0.4 %
Over-all Impact on VEC of All Desulfurization Processes Used	-	-	0.7%	0.4 %

^a See section 5.3 of this Draft RIA regarding the use of hydrodesulfurization, the Phillips S-Zorb Sulfur Adsorption process, and the Linde Isotherming process to meet the proposed sulfur standards.

^b NR = nonroad diesel fuel, L = locomotive diesel fuel, and M = marine diesel fuel.

^c HS refers to high-sulfur diesel fuel at the current uncontrolled average sulfur level of approximately 3400 ppm.

It is important to remember that the anticipated reduction in VEC discussed above would only apply to those gallons of nonroad diesel fuel that currently have a high sulfur content. Due to logistical constraints in the fuel distribution system, much of the fuel used in non-highway engines meets highway diesel fuel standards (see section 7.1 of this Draft RIA). The costs related to the reduction in non-highway diesel fuel VEC that would accompany the adoption of the proposed sulfur standards are discussed in section 7.3 of this Draft RIA.

5.9.3 Fuel Properties Related to Storage and Handling

In addition to fuel lubricity additives, a range of other additives are also sometimes required in diesel fuel to compensate for deficiencies in fuel quality. These additives include cold flow improvers, static dissipation additives, anti-corrosion additives, and anti-oxidants. The highway diesel fuel program projected that, except for an increase in the fuel lubricity additives, reducing the sulfur content of highway diesel fuel to meet a 15 ppm standard would not result in an increase in the use of diesel performance additives. Since that time, we have identified no new information which would alter that projection. Consequently, our estimate of the increase in additive use that would result from the adoption of today's proposed rule parallels that under the highway program. We estimate that the use of lubricity additives would increase, and that the use of other additives would be unaffected.

5.9.4 Cetane Index and Aromatics

We are proposing that nonroad, locomotive and marine diesel fuel would need to comply with the current highway diesel fuel requirements for cetane index or aromatics. Thus, these non-highway diesel fuels would have to meet either a 40 minimum cetane index, or a 35 maximum aromatics limit. In this subsection, we present information on what these properties are currently for nonhighway diesel fuel, then we estimate how much they are likely to change when these streams are desulfurized.

We have reports of non-highway diesel fuel cetane index values from refinery samples during the years 1997 through 2001. The 1997 and 1998 reports were published by the National Institute for Petroleum and Energy Research (NIPER), Bartlesville, OK, and then this organization changed their name to TRW Petroleum Technologies, which published the 1999 - 2001 reports. The reports divided the country into the Eastern, Southern, Central, Rocky Mountain, and Western Regions. The samples, which averaged about 17 per year, were pooled from the various regions. The range of cetane index values for the 85 total samples is 39.4 - 57.0. Out of the 85 samples 5, or 6 percent, were under the cetane index value of 40 and potentially would not comply with the proposed cetane index minimum of 40. However, those that were below the 40 cetane index proposed minimum, were barely below it (i.e. 39.4 versus 40). Since the aromatics levels were not provided for these 5 samples, we could not verify if these samples would also not comply with the aromatics part of the specification.

As refiners desulfurize their non-highway diesel fuel to comply with the 500 ppm cap standard in 2007 and then again to comply with the 15 ppm cap standard in 2010, they would be expected to experience an increase in the cetane levels of their non-highway diesel fuel. Vendors of the desulfurization technologies either provided information on the impact that their technologies have on the cetane index of diesel fuel, or we were able to calculate the impact using changes to API gravity and the T-50 distillation point. While the changes in cetane index were provided for the desulfurization of highway diesel fuel, they are applicable to non-highway diesel fuel as well as it is similar in quality and composition to highway diesel fuel. The estimated impact of the desulfurization technologies on cetane index summarized in the

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following table. As described in Chapter 7 of the Draft RIA, much of the high sulfur diesel pool is already hydrotreated (on the order of 50 percent in some PADDs) and would therefore not be impacted by the first step of fuel control to 500 ppm, so the cetane index is expressed as a range for the high sulfur to 500 ppm step. The lower value of the range reflects that refiners would only have to hydrotreat half of their existing high sulfur pool to produce 500 ppm sulfur fuel, while the upper value reflects that refiners would have to treat their entire pool. For conventional hydrotreating, a range in the amount of increase in cetane index values is also reflected in the 500 ppm to 15 ppm sulfur reduction step which reflects the different estimates for the two vendors which provided us the desulfurization information.

Table 5.9-2
Impact of Desulfurization Technologies on Diesel Fuel Cetane Index

	Conventional Hydrotreating	Linde Isotherming	Phillips S-Zorb
High Sulfur to 500 ppm	+2 to +4	+2 to +4	Very Small
500 ppm to 15 ppm	+1 to +2	+2	Very Small
Total High Sulfur to 15 ppm	+3 to +6	+4 to +6	Small

As summarized in the above table, conventional hydrotreating improves the cetane index of diesel fuel by 2 to 4 numbers for the 500 ppm sulfur cap standard, and 1 to 2 numbers for the 15 ppm sulfur cap standard incremental to the 500 ppm standard. If the lowest cetane index values of non-highway diesel fuel are indeed between 39 and 40 as the NIPER/TRW data suggests, then the desulfurization of that pool to comply with the 500 ppm sulfur standard, which is expected to be accomplished using conventional desulfurization technology, is expected to increase the cetane index to a value above the 40 minimum, thus refiners are not expected to be constrained by the a cetane index requirement.

Aromatics would also be expected to decrease, although this decrease is expected to occur mostly through the saturation of polynuclear aromatics to monoaromatics. The biggest decrease in aromatics is expected by conventional hydrotreating and Linde Isotherming. Phillips S-Zorb probably only reduces aromatics a minimal amount.

5.9.5 Other Fuel Properties

Desulfurization is expected to impact other qualities of non-highway diesel fuel. The concentration of nitrogen in current high sulfur diesel fuel is on the order of several hundred parts per million. The desulfurization technologies projected to be used in the cost analysis for compliance with the 500 ppm sulfur cap standard are expected to lower nitrogen levels down to under 100 ppm, although they may still be above 50 ppm. These same desulfurization technologies are expected to lower nitrogen levels down to under 10 ppm for compliance with the 15 ppm sulfur cap standard.

Conventional desulfurization and Linde Isotherming are expected to affect the distillation temperature of non-highway diesel fuel. For desulfurizing high sulfur diesel fuel down to 15 ppm, one vendor of conventional hydrotreating technology estimates that each distillation point (T-10 - T-90) would experience a 5 degree fahrenheit decrease. Consistent with that, API gravity would be expected to increase by 4 numbers, thus, density would experience a commensurate decrease. Linde Isotherming is expected to impact the distillation temperature less than conventional hydrotreating due to the lower API gravity increase caused by Linde compared to conventional hydrotreating. Phillips S-Zorb would likely not impact the distillation temperature.

5.10 Feasibility of the Use of a Marker in Heating Oil from 2007-2010 and in Locomotive and Marine Fuel from 2010-2014

We are proposing that the solvent yellow 124 marker be used in heating oil at a concentration of 6 milligrams per liter from June 1, 2007 through June 1, 2010. The marker would be required to be added to heating oil at the refinery gate just as visible evidence of the red dye is required today. Beginning June 1, 2010, the same marker at the same concentration would be required to be added to locomotive and marine diesel fuel until June 1, 2014. After June 1, 2014, our proposal would not require the use of a marker. Any fuel with a marker concentration of greater than 0.1 mg per liter would be precluded from use in NRLM equipment prior to 2010 and NR equipment after 2010.

Following is a discussion of our evaluation of the feasibility of the use of yellow solvent 124 as the specified fuel marker under the proposed NRLM fuel program and our rationale for selecting solvent yellow 124. The potential impacts of the proposed marker requirements on the fuel distribution system are contained in section 5.4 of this draft RIA. The costs associated with the proposed marker are discussed in section 7.3 of this draft RIA.

The qualification criteria for a marker under the proposed NRLM program include:

- 1) Solubility in diesel fuel under the range of conditions experienced in the distribution system from the refinery to the end-user.
- 2) Not naturally present in diesel fuel
- 3) Chemical stability under the range of conditions that can be experienced during storage and distribution of diesel fuel
- 4) Difficult to remove from fuel or obscure presence to avoid detection
- 5) Presence in fuel is positively identifiable using laboratory and field tests
- 6) Detectable in very small concentrations to reveal mixtures of marked and unmarked fuels
- 7) Economic acceptability, ready availability, and ease of application
- 8) No increased public health risk

There are a number of types of dyes and markers. Visible dyes are most common, are typically least expensive, and are easily detected in the field. Laboratory tests are often also available for such dyes to quantify the concentration of the dye present in fuel. This is the case with red dye 164 which is required by the U.S. IRS to be present in non-taxed diesel fuel at a

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minimum level that is spectrally equivalent to 3.9 pounds per thousand barrels (ptb) of the IRS-specified standard solvent red 26 dye. The longtime presence of a number of visible dyes in fuels means that their acceptability under the above qualification criteria has been well established.

However, using a second diesel dye for segregation of heating oil based on visual identification is problematic. Most dye colors that provide a strong visible trace in fuels are already in use for different fuel applications. More importantly, mixing two fuels containing different strong dyes can result in interference between the two dyes rendering identification of the presence of either dye difficult. Yet, the mixing of nonroad diesel fuel into heating oil for eventual sale as heating oil would be an acceptable and often an economically desirable practice. Furthermore, to avoid interfering with the IRS tax code, it would be advantageous to maintain the current red color. Based on these considerations, we believe that the use of a second strong dye to visibly segregate heating oil from NRLM is not practicable.

Fuel markers that do not depend on a visible trace for detection are beginning to see more use in branded fuels. Invisible markers are typically somewhat more expensive than visible markers. Soluble dyes have also been used at a concentration too low to allow reliable detection of their presence visually but that does allow detection by other means. When a dye is used in this fashion it is more appropriate to refer to it as a marker, since its functionality is not associated with the slight color it may impart to the fuel. Fuel markers typically have a simple method to detect the presence of the marker in the field and a more rigorous method to quantify the concentration of the marker in the fuel which must be conducted in the laboratory. Such laboratory methods are favored for developing strong evidence of noncompliance for use in enforcement actions.

Depending on the marker type, detection in the field is accomplished either by the addition of a chemical reagent or by their fluorescence when subjected to near-infra-red or ultraviolet light. Some chemical-based detection methods are more suitable for use in the field than others. For example, some are more suited for laboratory use due to the complexity of the detection process or concerns regarding the toxicity of the reagents used to reveal the presence of the marker. Ideally, after conducting a field test for the presence of the marker and finding the fuel to be compliant, the inspector returns the fuel sample to the fuel batch or otherwise ensures that it is used for the intended fuel purpose. This practice avoids the difficulty associated with disposing of the fuel sample. For most types of field tests for markers, however, this practice is not possible. The introduction of the reagent to the test fuel sample typically makes returning the fuel sample for its intended use impossible, and it must be disposed of by other means. The toxicity of the by-products from testing can also be a concern. Chemical-based field tests are typically inexpensive. However, if such tests produce toxic by-products, the cost of disposing of such by-products can be significant. In addition, there are public health concerns related to the potential improper disposal of such by-products.

Near-infra-red and ultra-violet fluorescent markers can be easily detected in the field using a small device that requires only brief training for the operator and leaves that sample unaffected. Therefore, concerns regarding test reagents and by-products are not an issue and the fuel sample

can be returned to the fuel batch. However, the devices used in the field detection of such markers can be more expensive..

There are also more exotic markers available such as based on immunoassay, and isotopic or molecular enhancement. Such markers typically can only be detected by laboratory analysis and are more expensive than the markers discussed above. Because of the lack of a easy field test, we believe that further consideration of the use of such markers for the proposed purpose is not warranted.

The Euromarker:

Effective in August 2002, the European Union (EU) enacted a marker requirement for diesel fuel that is taxed at a lower rate (which applies in all of the EU member states).⁴⁴ The marker selected by the EU is N-ethyl-N-[2-[1-(2-methylpropoxy)ethoxy]-4-phenylazo]-benzeneamine.⁴⁵ This compound is also referred to as solvent yellow 124 or the Euromarker. The treatment level required by the EU is 6 milligrams per liter. Despite its name, solvent yellow 124 does not impart a strong color to diesel fuel when used at the proposed concentration. The EU allows its member states to choose which visible dye to use in lower-taxed fuel in addition to the Euromarker. A number of countries in the EU use a red dye.⁴⁶ The Euromarker imparts a slight orange shade to fuel that is dyed red. However, experience of the EU members has shown the fuel containing red dye and the Euromarker is still recognizable as red dyed diesel fuel.⁴⁷ The specific type of red dye used in Europe is not the same type used in the U.S. Nevertheless, we believe that the experience of EU member states that the Euromarker does not interfere with the identification of the presence of strong red dyes in diesel fuel is sufficiently predictive of its potential impact on the color that the IRS red dye impart to diesel fuel. Therefore, we do not expect that the presence of solvent yellow 124 in diesel fuel that contains the IRS-specified red dye would interfere with the use of the red dye by IRS to identify non-taxed fuels.

Solvent yellow 124 is substantially similar to diesel fuel and is registered under EPA's Fuel and Fuel Additive program which evaluates an additive's suitability for use based on the potential effects on human health and vehicle emissions performance. In addition, extensive evaluation and testing of the Euromarker was conducted by the European Commission. This included combustion testing which showed no detectable difference between the emissions from marked and unmarked fuel. We also understand that Norway specifically evaluated the use of distillate fuel containing the Euromarker for heating purposes and determined that the presence of the Eurmarker did not cause an increase in harmful emissions from heating equipment. Based on the European experience with the Euromarker, we do not expect that there would be concerns regarding the compatibility of the Euromarker in the U.S. fuel distribution system or for use in motor vehicle engines and other equipment such as in residential furnaces. The European Union intends to review the use of Euromarker after December 2005, or earlier if any health and safety or environmental concerns about its use are raised. We intend to keep abreast of such activities and may initiate our own review of the use of the Euromarker depending on the European Union's findings.

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Fuel additives are typically required to be tested for their suitability for use under the unique conditions present in aircraft engines and fuel supply systems before they are allowed to be present in jet fuel. Due to safety concerns, jet fuel is held to very strict standards regarding the allowable presence of contaminants and additives that are not specifically allowed for use in jet fuel. For example, the Department of Defense (DoD) maintains a zero-tolerance for any contamination of jet fuel with the red dye required by the IRS (and EPA). Given their past experience with red dye, DoD raised concerns regarding the extent to which jet fuel might become contaminated with solvent yellow 124 due to the presence of solvent yellow 124-containing fuels and jet fuel in the U.S. common carrier pipeline distribution system, and whether any such contamination might be cause for concern.

We do not believe that there any significant pathways for such contamination to take place other than by potential human error. In addition, the fact that the fuel distribution industry in the U.S. has been successful in managing contamination of jet fuel with red dye indicates that the potential contamination of jet fuel with the solvent yellow 124 can also be successfully managed in the US fuel distribution system. Therefore, we believe that our proposed use of solvent yellow 124 should not pose a significant risk to the maintenance of jet fuel purity.

There is currently no official procedure recognized by the European Union to quantify the presence of the Euromarker in distillate fuels. The most commonly accepted method used in the European Community is based on the chemical extraction of the Euromarker using hydrochloric acid solution and cyclohexane, and the subsequent evaluation of the extract using a visual spectrometer to determine the concentration of the Euromarker.⁴⁸ This test is inexpensive and easy to use for field inspections. However, the test involves reagents that require some safety precautions and the small amount of fuel required in the test must be disposed of as hazardous waste. Nevertheless, we believe that such safety concerns are manageable here in the U.S. just as they are in Europe and that the small amount of waste generated can be handled along with other similar waste generated by the company conducting the test, and that the associated effort/costs would be negligible.

Similar to the approach proposed regarding the measurement of fuel sulfur content, we are proposing a performance based procedure to measure the concentration of solvent yellow 124 in distillate fuel. Under the performance-based approach, a given test method could be approved for use in a specific laboratory or for field testing by meeting certain precision and accuracy criteria. There would be no designated marker test method. Properly selected precision and accuracy values potentially would allow multiple methods and multiple commercially available instruments to be approved, thus providing greater flexibility in method and instrument selection while also encouraging the development and use of better methods and instrumentation in the future. For example, we are hopeful that with more time and effort a simpler test can be developed that can avoid the use of reagents and the generation of hazardous waste that is by product of the current commonly accepted method.

In developing the precision and accuracy criteria for the sulfur test method, EPA drew upon the results of an interlaboratory study conducted by the American Society for Testing and

Materials (ASTM) to support ASTM's standardization of the sulfur test method. Unfortunately, there has not been sufficient time for industry to standardize the test procedure used to measure the concentration of solvent yellow 124 (Euromarker) in distillate fuels or to conduct an interlaboratory study regarding the variability of the method. Nevertheless, the European Union has been successful in implementing its Euromarker requirement while relying on the marker test procedures which are currently available. As referenced above, the most commonly accepted method used in the European Union is a visual spectrometer-based procedure. We are proposing to use this procedure to establish the precision and accuracy criteria on which a marker test procedure would be approved under the performance based approach..

There has been substantial experience in the use of the proposed reference market test method since the August 2002 effective date of the European Union's Euromarker requirement. However, EPA is aware of only limited summary data on the variability of the reference test method from a manufacturer of the visible spectrometer apparatus used in the testing.⁴⁹ The stated resolution of the test method from in the materials provided by this equipment manufacturer is 0.1 mg/L, with a repeatability of plus or minus 0.08 mg/L and a reproducibility of plus or minus 0.2 mg/L. In the lack of more extensive data, we are proposing to use these available data as the basis of our proposed precision and accuracy criteria as discussed below. The referenced repeatability and reproducibility are terms related to test variability used by ASTM in defining their voluntary consensus test standards. ASTM defines repeatability as the difference between successive results obtained by the same operator with the same apparatus under constant operating conditions on identical test materials that would, in the long run, in the normal and correct operation of the test method be exceeded only in one case in 20. Reproducibility is defined by ASTM as the difference between two single and independent results obtained by different operators working in different laboratories on identical material that would, in the long run, be exceeded only in one case in twenty.

The first qualification criterion, precision, refers to the consistency of a set of measurements and is used to determine how closely analytical results can be duplicated based on repeat measurements of the same material under prescribed conditions. To demonstrate the precision of a given marker test method under the performance-based approach, a laboratory facility would perform 20 repeat tests over several days on samples taken from a homogeneous supply of a commercially available diesel fuel that contains the marker. Using a similar methodology to that employed in deriving the proposed sulfur test procedure precision value, results in a precision value for the marker test procedure of 0.043 mg/L. This value was derived as follows: 0.43 mg/L is equal to 1.5 times the standard deviation (0.029) where the standard deviation is equal to the repeatability of the reference test method (0.08 mg/L) divided by 2.77. Since the conditions of the precision qualification test admit more sources of variability than the conditions under which ASTM repeatability is determined (longer time span, different operators, environmental conditions, etc.) the repeatability standard deviation derived from the repeatability value was multiplied by what we believe to be a reasonable adjustment factor, 1.5 to compensate for the difference in conditions.

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We are concerned that the use of the 0.043 mg/L precision value derived above, because it is based on very limited data, might preclude the acceptability of test procedures that would be adequate for the intended regulatory use. In addition, the lowest measurement of marker concentration that would have relevance under the proposed regulations is 0.1 mg per liter. Consequently, we are proposing that the precision of a test procedure would need to be less than 0.1 mg/L for it to qualify.

The second criterion, accuracy, refers to the closeness of agreement between a measured or calculated value and the actual or specified value. To demonstrate the accuracy of a given test method under the performance-based approach, a laboratory facility would be required to perform 10 repeat tests, the mean of which could not deviate from the Accepted Reference Value (ARV) of the standard by more than 0.05 mg/L. We believe that the proposed accuracy level is not overly restrictive, while being sufficiently protective considering that the lowest marker level of regulatory significance would be 0.1 mg/L.

These tests would be performed using commercially available solvent yellow 124 standards. Ten tests would be required using each of two different marker standards, one in the range of 0.1 to 1 mg/L and the other in the range of 4 to 10 mg/L of solvent yellow 124. We selected the two ranges of the marker standards to cover the two marker concentrations that are of most regulatory concern: 6 mg/L is the minimum marker concentration required in fuels that we are proposing must contain the marker, while 0.1 mg/L is the maximum allowed concentration for fuel to be considered as not containing the fuel marker for the purposes of the fuel use restrictions on which the fuel marker requirements are based.

We believe that these precision and accuracy criteria would limit the allowed test procedures to those capable of satisfying the intended use for enforcement and affirmative defenses to presumptive liability purposes, while not being overly restrictive.

Solvent yellow 124 is marketed by several manufactures and is in current wide-scale use in the European community. We anticipate that these manufactures would have sufficient lead-time to increase their production of solvent yellow 124 to supply the increase in demand that would result from the proposed marker provisions.

The proposed treatment rate would ensure adequate detection in the distribution system even if diluted by a factor of 50. Removal of the marker is possible through an expensive laundering process. However, we believe that there would be little economic incentive to attempting to the remove the marker in the United States given that its removal would only allow the use of the fuel in other nontaxed applications. Even if the marker were removed, the IRS red dye would still be present to prevent the use of the fuel for highway (taxed) purposes.

Other Potential Candidate Fuel Markers:

We considered other potential markers that might be used to identify and segregate heating oil from NRLM fuel. One of the potential alternatives that we identified is the Clir-Code® marker system manufactured by ISOTAG Technologies Inc. The Clir-Code® marker system has

been used extensively in U.S. fuel and includes a field test that employs a hand-held near infrared detector which does not require the use of any reagents. EPA deferred proposing the use of the Clir-Code® marker because we believe that the advantage of a simpler field test would not compensate for the increased treatment cost relative to the use of the Euromarker

Appendix 5A: EPA's Legal Authority for Proposing Nonroad, Locomotive, and Marine Diesel Fuel Sulfur Controls

We are proposing diesel fuel sulfur controls under our authority in section 211(c)(1) of the Clean Air Act. This section gives us the authority to “control or prohibit the manufacture, introduction into commerce, offering for sale, or sale” of any fuel or fuel additive for use in a nonroad engine or vehicle (1) whose emission products, in the judgment of the Administrator, cause or contribute to air pollution which may reasonably be anticipated to endanger the public health or welfare or (2) whose emission products will impair to a significant degree the performance of any emission control device or system which is in general use, or which the Administrator finds has been developed to a point where in a reasonable time it would be in general use were the fuel control or prohibition adopted.

We currently do not have regulatory requirements for sulfur in nonroad, locomotive, or marine diesel fuel. Beginning in 1993, highway diesel fuel was required to meet a sulfur cap of 500 ppm and be segregated from other distillate fuels as it left the refinery by the use of a visible level of dye solvent red 164 in all non-highway distillate. Any fuel not dyed is treated as highway fuel.

We are proposing controls on sulfur levels in nonroad diesel fuel based on both of the Clean Air Act criteria described above. Under the first criterion, we believe that emission products of sulfur in nonroad, locomotive, and marine diesel fuel used in these engines contribute to PM and SO_x pollution. As discussed in Chapter 2, emissions of these pollutants cause or contribute to ambient levels of air pollution that endanger public health and welfare. Control of sulfur to 500 ppm for this fuel will lead to significant, cost-effective reductions in emissions of these pollutants. Under the second criterion, we believe that sulfur in nonroad diesel fuel will significantly impair the emission-control systems expected to be in general use in nonroad engines designed to meet the proposed emission standards. Chapter 4 describes the substantial adverse effect of high fuel-sulfur levels on the emission-control devices or systems for diesel engines meeting the proposed emission standards. Controlling sulfur levels in nonroad diesel fuel to 15 ppm will enable emission-control technology that will achieve significant, cost-effective reduction in emissions of these pollutants. The following sections summarize our analysis of the various issues related to adopting fuel-sulfur controls for nonroad, locomotive, and marine diesel fuel.

5A.1 Health and Welfare Concerns of Air Pollution Caused by Sulfur in Diesel Fuel

At the current unregulated levels of sulfur in this diesel fuel, the emission products from the combustion of diesel sulfur in these engines can reasonably be anticipated to endanger public health and welfare. Sulfur in nonroad, locomotive and marine diesel fuel leads directly to emissions of SO₂ and sulfate PM from the exhaust of diesel vehicles, both of which cause adverse health and welfare impacts, as described in Chapter 2. SO₂ emissions from nonroad, locomotive and marine engines are directly proportional to the amount of sulfur in the fuel. SO₂

is oxidized in the atmosphere to SO₃ which then combines with water to form sulfuric acid (H₂SO₄) and further combines with ammonium in the atmosphere to form ammonium sulfate aerosols. These aerosols are what is often referred to as sulfate PM. This sulfate PM comprises a significant portion of the “secondary” PM that does not come directly from the tailpipe, but is nevertheless formed in the atmosphere from exhaust pollutants. Exposure to secondary PM may be different from that of PM emitted directly from the exhaust, but the health concerns of secondary PM are just as severe as for directly emitted particulate matter, with the possible exception of the carcinogenicity concerns with diesel exhaust.

Approximately 1-2% of the sulfur in nonroad, locomotive and marine diesel fuel is not converted into SO₂, but is instead further oxidized into SO₃ which then forms sulfuric acid aerosols (sulfate PM) as it leaves the tailpipe. While only a small fraction of the overall sulfur is converted into sulfate emissions in the exhaust, it nevertheless accounts for approximately 10% of the total PM emissions from diesel engines today. This sulfate PM is also directly proportional to the sulfur concentration in the fuel. The health and welfare implications of emissions of PM and SO₂ and the need for reductions in these emissions are discussed in Chapter 2.

The proposed first step in the reduction in the sulfur level of nonroad, locomotive, and marine diesel fuel to 500 ppm would achieve approximately a 90 percent reduction in the emissions of SO₂ and sulfate PM emissions from nonroad, locomotive, and marine diesel engines compared to today’s levels. The proposed second step of nonroad sulfur control to 15 ppm (and the control of locomotive and marine diesel fuel also being considered) would achieve in excess of a 99 percent reduction in these pollutants. The rationale for the two-step approach to fuel sulfur control is discussed in Chapters 5 and 12. Aside from its dramatic and immediate in-use emission benefits, the proposed sulfur level of 500 ppm for the first step was chosen primarily due to its consistency with the current highway diesel fuel standard. The magnitude of the distribution system costs would virtually prohibit the widespread distribution of any other grades of diesel fuel, as discussed in Section IV.B of the preamble to the proposed rule. Consequently, the choice of sulfur level was limited to one of the existing three grades; 15 ppm, 500 ppm, or uncontrolled. A reduction in the sulfur directly to 15 ppm was inconsistent with the proposed 2-step approach to diesel fuel sulfur control. Therefore, given the need to achieve reductions, the 500 ppm level was selected for this temporary first step of control.

Section 211(c)(2)(A) requires that, prior to adopting a fuel control based on a finding that the fuel’s emission products contribute to air pollution that can reasonably be anticipated to endanger public health or welfare, EPA consider “all relevant medical and scientific evidence available, including consideration of other technologically or economically feasible means of achieving emission standards under [section 202 of the Act].” EPA’s analysis of the medical and scientific evidence relating to the emissions impact from nonroad, locomotive and marine engines, which are impacted by sulfur in diesel fuel, is described in more detail in Chapter 2.

EPA has also satisfied the statutory requirement to consider “other technologically or economically feasible means of achieving emission standards under section [202 of the Act].” This provision has been interpreted as requiring consideration of establishing emission standards

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under section 202 prior to establishing controls or prohibitions on fuels or fuel additives under section 211(c)(1)(A). See *Ethyl Corp. v. EPA*, 541 F.2d. 1, 31-32 (D.C. Cir. 1976). In *Ethyl*, the court stated that section 211(c)(2)(B) calls for good faith consideration of the evidence and options, not for mandatory deference to regulation under section 202 compared to fuel controls. *Id.* at 32, n.66.

EPA recently set emissions standards for heavy-duty highway diesel engines under section 202 (66 FR 5002, January 18, 2001). That program will reduce particulate matter and oxides of nitrogen emissions from heavy duty engines by 90 percent. In order to meet these more stringent standards for diesel engines, the program requires a 97 percent reduction in the sulfur content of diesel fuel. EPA does not believe it is appropriate to seek further reductions at this time from these engines. Also, section 211(c)(1)(A) refers to standard setting under section 202 for highway engines or vehicles, and does not refer to standard setting under section 213. In any case, EPA is proposing stringent new standards for nonroad diesel engines under section 213.

The nonroad, locomotive and marine diesel sulfur standards of 500 ppm proposed today represent an appropriate exercise of the Agency's discretion under section 211(c)(1)(A). The 500 ppm level is consistent with current highway diesel fuel (until 2010) and adopting the same level for nonroad, locomotive, and marine diesel fuels avoids costs associated with more grades of fuel in the distribution system. The 500 ppm level also will achieve significant and cost-effective environmental benefits, providing approximately 90 percent of the sulfate PM and SO₂ benefits associated with control to 15 ppm. It also allows for a short lead time for implementation, enabling the environmental benefits to begin as soon as possible.

5A.2 Impact of Diesel Sulfur Emission Products on Emission-Control Systems

EPA is also proposing to restrict the sulfur content of nonroad diesel fuel nationwide to no more than 15 ppm, beginning in 2010 to enable compliance with new emission standards based on the use of advanced emission control technology that will be available to nonroad diesel engines. EPA believes that sulfur in nonroad diesel fuel would significantly impair the emission-control technology of nonroad engines designed to meet the proposed emission standards. We know that diesel sulfur has a negative impact on engine emission controls. This is not a new development. As discussed in Chapter 4, we believe existing aftertreatment technologies will be capable of achieving dramatic reductions in NO_x and PM emissions from nonroad engines for the 2009 time frame. The aftertreatment technology for PM is already in an advanced state of development and being tested in fleet demonstrations in the U.S. and Europe. The NO_x aftertreatment technology is in a less-advanced, but still highly promising state of development, and as discussed in Chapter 4, EPA believes the lead time between now and 2011 will provide ample opportunity to adapt this technology for feasible operation on nonroad engines. EPA believes these aftertreatment technologies would be in general use by 2009 and 2011, respectively, with the diesel sulfur controls proposed in this rule.

These aftertreatment technologies are ineffective in reducing NO_x and PM emissions and incapable of being introduced widely into the marketplace at the nonroad diesel sulfur concentrations typical today or less. Not only does their efficiency at reducing NO_x and PM emissions fall off dramatically at elevated fuel sulfur concentrations, but engine operation impacts and permanent damage to the aftertreatment systems are also possible. In order to ensure regeneration of the diesel particulate filter at exhaust temperatures typical of nonroad diesel engines as described in Chapter 4, we are expecting that significant amounts of precious group metals (primarily platinum) will be used in their washcoat formulations. There are two primary mechanisms by which sulfur in nonroad diesel fuel can limit the effectiveness or robustness of diesel particulate filters which rely on a precious metal oxidizing catalyst. The first is inhibition of the oxidation of NO to NO₂ and the second is the preferential oxidation of SO₂ to SO₃, forming a precursor to sulfate particulate matter. With respect to NO_x aftertreatment, all of the NO_x aftertreatment technologies discussed in Chapter 4 that EPA believes will generally be available to meet the proposed standards are expected to utilize platinum to oxidize NO to NO₂ to either: improve the NO_x reduction efficiency of the catalysts at low temperatures; or, as in the case of the NO_x absorber, as an essential part of the process of NO_x storage and regeneration. This reliance of NO₂ as an integral part of the reduction process means that the NO_x aftertreatment technologies, like the PM aftertreatment technologies, would be significantly impaired by the sulfur in nonroad diesel fuel. Sulfur, in the form of SO_x, competes with NO_x to be stored by the aftertreatment device. The resulting sulfate is harder to break down than the stored NO_x, and is not normally released during the regeneration phase (i.e. SO_x is stored preferentially to NO_x by the device). The sulfur therefore continues to build up, preventing storage of NO_x, and rendering the device ineffective. Further, although this problem can be addressed by adding a “desulfation” phase to aftertreatment operation, the number of these desulfation events needs to be minimized in order to prevent damage to the aftertreatment device.

5A.3 Sulfur Levels that Nonroad Engines Can Tolerate

As discussed in Chapter 4, there are three key factors which when taken together lead us to conclude that a nonroad diesel sulfur cap of 15 ppm is necessary so the NO_x and PM aftertreatment technology on nonroad engines will function properly and be able to meet the proposed emission standards. These factors, as discussed in more detail in Chapter 4, are the implications sulfur levels in excess of 15 ppm would have on the efficiency and reliability of the systems and their impact on the fuel economy of the engine.

The efficiency of emission control technologies at reducing harmful pollutants is directly impacted by sulfur in nonroad diesel fuel. Initial and long term conversion efficiencies for NO_x, HC, CO and diesel PM emissions are significantly reduced by catalyst poisoning and catalyst inhibition due to sulfur. NO_x conversion efficiencies with the NO_x adsorber technology in particular are dramatically reduced in a very short time due to sulfur poisoning of the NO_x storage bed. In addition, total PM control efficiency is negatively impacted by the formation of sulfate PM. The formation of sulfate PM is likely to be in excess of the total PM standard proposed today, unless nonroad diesel fuel sulfur levels are below 15 ppm. When sulfur is kept

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at these low levels, both PM and NO_x aftertreatment devices are expected to operate at high levels of conversion efficiency, allowing compliance with the PM and NO_x emission standards.

The reliability of the emission control technologies to continue to function as required under all operating conditions for the life of the engine is also directly impacted by sulfur in nonroad diesel fuel. As discussed in Chapter 4, sulfur in nonroad diesel fuel can prevent proper operation and regeneration of both NO_x and PM advanced aftertreatment control technologies leading to permanent loss in emission control effectiveness and even catastrophic failure of the systems. For example, if regeneration of a PM filter does not occur, catastrophic failure of the filter could occur in less than a single tank full of high sulfur nonroad diesel fuel. For NO_x adsorbers, keeping sulfur levels no higher than 15 ppm is needed to minimize the number of desulfation events to provide a high efficiency operation over the useful life of the engine. It is only through the availability of nonroad diesel fuel with sulfur levels less than 15 ppm that the reliability of these technologies can be raised to the point where they become feasible for successful use by nonroad engines. We believe that diesel fuel sulfur levels of 15 ppm are needed and would allow these technologies to operate properly throughout the life of the vehicle, including proper periodic or continuous regeneration.

The sulfur content of nonroad diesel fuel will also impact the fuel economy of nonroad engines equipped with NO_x and PM aftertreatment technologies. As discussed in detail in Chapter 4, NO_x adsorbers are expected to consume nonroad diesel fuel in order to cleanse themselves of stored sulfates and maintain efficiency. The larger the amount of sulfur in nonroad diesel fuel, the greater this adverse impact on fuel economy. As sulfur levels increase above 15 ppm the fuel economy impact transitions quickly from merely noticeable to unacceptable. Likewise PM trap regeneration is inhibited by sulfur in nonroad diesel fuel. This leads to increased PM loading in the diesel particulate filter, increased exhaust backpressure, and poorer fuel economy. Thus for both NO_x and PM technologies, the lower the fuel sulfur level the better the fuel economy of the vehicle.

As a result of these factors, we believe that 15 ppm represents an upper threshold of acceptable nonroad diesel fuel sulfur levels and are therefore proposing to cap in-use sulfur levels there.

5A.4 Sulfur Sensitivity of Other Catalysts

Section 211(c)(2)(B) requires that, prior to adopting a fuel control based on a significant impairment to vehicle emission-control systems, EPA consider available scientific and economic data, including a cost benefit analysis comparing emission-control devices or systems which are or will be in general use that require the proposed fuel control with such devices or systems which are or will be in general use that do not require the proposed fuel control. As described below, we conclude that the aftertreatment technology expected to be used to meet the proposed nonroad standards would be significantly impaired by operation on high sulfur nonroad diesel fuel. Our analysis of the available scientific and economic data can be found elsewhere in this document, including an analysis of the environmental benefits of the proposed control (Chapter

3), an analysis of the costs and the technological feasibility of controlling sulfur to the proposed levels (Chapter 7), and a cost-effectiveness analysis of the proposed sulfur control and nonroad emission standards (Chapter 8). Under section 211(c)(2)(B), EPA is also required to compare the costs and benefits of achieving emission standards through emission-control systems that would not be sulfur-sensitive, if any such systems are or will be in general use.

We have determined that there are not (and will not be in the foreseeable future) emission control devices available for general use in nonroad engines that can meet the proposed nonroad emission standards and would not be significantly impaired by nonroad diesel fuel with high sulfur levels. NO_x and PM emissions cannot be reduced anywhere near the magnitude contemplated by the standards proposed today without the application of aftertreatment technology. As discussed in Chapter 4, there are a number of aftertreatment technologies that are currently being developed for both NO_x and PM control with varying levels of effectiveness, sulfur sensitivity, and potential application to nonroad engines.

As discussed in Chapter 4, all of the aftertreatment technologies that could be used to meet the PM or NO_x standards are significantly impaired by the sulfur in diesel fuel. For PM control, EPA is not aware of a PM aftertreatment technology that is capable of meeting the PM standard adopted today and that would not need the level of sulfur control adopted in this rule. In addition, the NO_x aftertreatment technologies evaluated by EPA all rely on the use of catalytic processes to increase the effectiveness of the device in reducing NO_x emissions. For example both NO_x adsorbers and compact SCR would rely on noble metals to oxidize NO to NO₂, to increase NO_x conversion efficiency at the lower exhaust temperatures found in diesel motor vehicle operation. This catalytic process, however, produces sulfate PM from the sulfur in the diesel fuel, and these NO_x aftertreatment devices need the level of sulfur control adopted in this rule in order for the vehicle to comply with the PM standard.

In addition, compact SCR is not a technology that would be generally available by the model year 2011 time frame. Significant and widespread changes to the fuel distribution system infrastructure would have to be made and in place by then, and there is no practical expectation that this would occur, with or without the low sulfur standard adopted today. While it is feasible and practical to expect that compact SCR may have a role in specific controlled circumstances, such as certain centrally fueled fleets, it is not realistic at this time to expect that the fuel distribution system infrastructure changes needed for widespread and general use of compact SCR on nonroad engines will be in place by the model year 2011 time frame. In addition, even if SCR were used to obtain the emission performance required by today's standards, it is not clear that the vehicles would continue to maintain that level of performance in-use. Finally, for NO_x control, both NO_x adsorbers and compact SCR are significantly impaired by sulfur in diesel fuel, and both technologies would need very large reductions in sulfur from current levels to meet the NO_x standard adopted today. EPA believes that the requirement of a cost benefit analysis under section 211(c)(2)(B) is not aimed at evaluating emission-control technologies that would require significant additional or different EPA fuel control regulations before the technology could be considered generally available.

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In sum, EPA believes that both PM and NO_x aftertreatment technologies require the level of sulfur control adopted today to meet the PM standards. There is no PM or NO_x emission-control device or system that would be in general use that does not need this level of sulfur control for purposes of controlling PM. EPA also believes that the only NO_x aftertreatment technologies that would be considered generally available for use to meet the NO_x standard, need the level of sulfur adopted today to be considered generally available for use to meet the NO_x standard.

As described in Chapter 4, EPA anticipates that all the nonroad engine technologies expected to be used to meet the final nonroad standards will require the use of low sulfur nonroad diesel fuel. If we do not control diesel sulfur to the finalized levels, we would not be able to set nonroad standards as stringent as those we are finalizing today. Consequently, EPA concludes that the benefits that would be achieved through implementation of the engine and sulfur control programs cannot be achieved through the use of emission control technology that does not need the sulfur control adopted in this rule, and would be generally available to meet the emission standards adopted in this rule.

This also means that if EPA were to adopt emission standards without controlling diesel sulfur content, the standards would be significantly less stringent than those finalized today based on what would be technologically feasible with current or 500 ppm sulfur levels.

5A.5 Effect of Nonroad Diesel Sulfur Control on the Use of Other Fuels or Fuel Additives

Section 211(c)(2)(C) requires that, prior to prohibiting a fuel or fuel additive, EPA establish that such prohibition will not cause the use of another fuel or fuel additive “which will produce emissions which endanger the public health or welfare to the same or greater degree” than the prohibited fuel or additive. This finding is required by the Act only prior to prohibiting a fuel or additive, not prior to controlling a fuel or additive. Since EPA is not proposing to prohibit sulfur in nonroad, locomotive or marine fuel, but rather to control the levels of sulfur in these diesel fuels, this finding is not required prior to regulation. However, EPA does not believe that the proposed sulfur control will result in the use of any other fuel or additive that will produce emissions that will endanger public health or welfare to the same or greater degree as the emissions produced by nonroad diesel with uncontrolled sulfur levels.

Unlike in the case of unleaded gasoline in the past where lead was providing a primary function in providing the necessary octane for the vehicles to function properly, sulfur does not serve any useful function in nonroad, locomotive or marine diesel fuel. It is not added to diesel fuel, but comes naturally in the crude oil into which diesel fuel is processed. If it were not for the fact that it costs money to remove sulfur from diesel fuel, it would have been removed years ago to improve the maintenance and durability characteristics of diesel engines. EPA is unaware of any function of sulfur in nonroad, locomotive or marine diesel fuel that might have to be replaced once sulfur is removed, with the possible exception of lubricity characteristics of the fuel. As discussed in Chapters 4 and 5, there is some evidence to suggest that as sulfur is removed from diesel fuel the natural lubricity characteristics of diesel fuel may be reduced. Depending on the

crude oil and the manner in which desulfurization occurs some low sulfur diesel fuels can exhibit poor lubricity characteristics. To offset this concern lubricity additives are sometimes added to the diesel fuel. These additives, however, are already in common use today and EPA is unaware of any health hazards associated with the use of these additives in diesel fuel and would merely be used in larger fractions of the diesel fuel pool. We do not anticipate that their use would produce emissions which would reduce the large public health and welfare benefits that this rule would achieve.

EPA is unaware of any other additives that might be necessary to add to nonroad, locomotive or marine diesel fuel to offset the existence of sulfur in the fuel. EPA is also unaware of any additives that might need to be added to nonroad, locomotive or marine diesel fuel to offset any other changes to the fuel which might occur during the process of removing sulfur. As we move forward with this rulemaking and its implementation we will continue to investigate this issue, and welcome any comment on it.

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